Australian Energy Market Commission

REVIEW

**FINAL REPORT**

# REVIEW OF THE REGULATORY FRAMEWORK FOR METERING SERVICES

30 AUGUST 2023

## INQUIRIES

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

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: EMO0040

## ABOUT THE AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

## ACKNOWLEDGEMENT OF COUNTRY

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

## COPYRIGHT



## CITATION

To cite this document, please use the following:
AEMC, Review of the regulatory framework for metering services, Final report, 30 August 2023

# EXECUTIVE SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has reviewed the regulatory framework for metering services having regard to previous reforms introducing competition in metering, and the future requirements of metering services in a transitioning energy system.

2 This report sets out a new reform agenda, enabling an accelerated deployment of smart meters to consumers in a timely and cost-effective way, to maximise benefits for all consumers. Faster replacement of legacy meters will enable consumers to access the benefits that smart meters can provide sooner.

3 Our findings and final recommendations outlined below reflect feedback and input provided to us by a wide group of committed stakeholders over several rounds of engagement. This collaborative effort has been instrumental in identifying opportunities to shape priority reforms and improve the current regulatory framework, in order to deliver better customer outcomes.

## BOX 1: KEY RECOMMENDATIONS

1. **Speeding up smart meter deployments** | Smart meter deployment supports the transition of the Australian energy system to Net Zero. A faster deployment will enable customers and the parties that service them to access the benefits of smart meters more quickly. The Commission recommends a target of universal uptake of smart meters by 2030 in NEM jurisdictions. Distribution network service providers (DNSPs) would develop an annual schedule to retire legacy accumulation and manually read meters. Retailers would then be responsible for installing smart meters at these sites over the five-year acceleration period.
2. **Supporting a positive customer experience in the transition to smart meters** | We have identified new customer safeguards and improvements to existing arrangements to support a more positive customer experience in the transition to smart meters. We have developed measures to protect customers from unexpected cost increases and provide them with clearer information and rights under the framework.
3. **Improving meter installation processes** | We have identified opportunities to improve efficiencies and customer outcomes in the current metering framework. We have developed measures to improve transparency and information availability for customers, reduce the regulatory burden on retailers and DNSPs, reduce delays in meter replacements and facilitate better coordination between industry.
4. **Unlocking further benefits from smart meter data and services**| We have developed measures to improve access to a broader range of data and services provided by smart meters, so that customers and the industry can derive greater benefits from this investment. We recommend improved customer access to real-time data, and DNSP access to Power Quality Data from smart meters.

## Smart meters support and get the most value out of the energy transition

4 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. Households will become smarter and more autonomous over time and will increasingly interact with the grid and energy markets (either actively or passively). Smart meters are an important tool that facilitate interaction, contributing to the cost effective decarbonisation of the energy market.

5 The timely deployment of smart meters is a critical enabler for the market bodies' broader consumer energy resources (CER) integration work program. All consumers benefit from a more efficient and a lower-cost energy system.

6 Many energy policy reforms rely on a digital foundation. Information is valuable. It can reduce costs and open up opportunities for innovation.

7 Smart meters support the provision of electricity services and help facilitate the efficient integration of CER — such as solar photovoltaic (PV) systems, home batteries and electric vehicles (EVs). Better information on customer usage can unlock the value of lower cost CER and demand response in order to efficiently meet customer needs, while ensuring reliability and security of the power system.

8 Smart meters provide consumers with visibility and control of their electricity consumption and costs, and more access to alternative pricing options. Smart meters create opportunities for greater data sharing, promoting competition and innovation, and supporting more targeted energy policies.

9 Better information can improve efficiency of operation, use and planning of networks. This can reduce costs and unlock greater CER hosting capacity — allowing customers increased export limits. Smart meters also create indirect system-wide benefits to households via DNSPs, retailers and AEMO.

10 Further, the data and information provided by smart meters can also allow DNSPs to improve their management of customer outages. Smart meters can also offer a dependable and uniform pathway for near-real-time data delivery and control services. Finally, smart meters can improve safety outcomes — such as through detection of neutral integrity failures, which can cause hazardous voltages to be present in accessible areas, and detection of over or under voltages, which can cause equipment failure.

## Accelerating the deployment of smart meters to benefit customers

11 The metering framework already provides a pathway for legacy meters to be phased out over time. Smart meters are currently being installed on a new and replacement basis — in addition to some proactive deployments by retailers, and through customer requests.

12 However, it is now clear and widely agreed by industry that this approach will not lead to smart meters being deployed fast enough to support the transition to the future energy system.

13 Bringing forward the installation of smart meters will achieve process efficiencies and economies of scale, increasing net benefits to consumers. While some costs will be incurred earlier, they will be lower in the future and overall. Customers will also be able to access benefits sooner, including being able to better manage their energy bills by choosing to switch tariffs or change behaviour when they are better off doing so.

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

14 The Commission engaged an independent expert consultant to undertake an economic cost–benefit assessment of accelerating the deployment of smart meters across the National Electricity Market (NEM). The assessment considered the economic costs and benefits of an accelerated deployment of smart meters targeting universal penetration by 2030.

15 Overall, we found that there are significant net benefits from the accelerated deployment of smart meters. This finding holds even based on only a limited set of highly achievable benefits, including benefits derived from:

- reduced costs for routine meter reading and special reads
- reduced meter installation costs due to the 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).

16 We also tested the robustness of these results under different scenarios and found that, even with higher smart metering costs, accelerating the roll-out would still deliver benefits to customers.

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

17 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 enable 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 have seen significant customer and stakeholder support.

18 Realising the benefits of new and innovative services is dependent on a 'critical mass' of smart meters and data access. Economies of scale are required for market participants to justify new investments in innovative customer services. Many network optimisation benefits, which flow through to customers, also rely on a minimum uptake of smart meters.

### The Commission's final recommendation is the universal deployment of smart meters by 2030

19 The Commission recommends a target of universal take-up 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. Tasmania has a program in place to accelerate smart meter deployment by 2026. Victoria has already achieved a near-universal uptake of smart meters.

20 There is wide support for new measures to achieve the timely deployment of smart meters in the NEM to benefit all customers. In our view, a 2030 timeframe is realistically achievable. Feedback from stakeholders generally suggests that the metering industry is well positioned to meet this timeframe.

### Our recommendations realise the benefits of the current industry structure

21 The Commission considers the current industry structure remains appropriate in the context of the acceleration program. The current arrangements are expected to be able to deliver the innovation and service benefits envisaged under the 2015 *Competition in metering* rule change.

22 We have considered alternative industry structures and found the resulting disruptions and delays would outweigh the benefits. Further submissions to the draft report proposed changing metering responsibilities whereby DNSPs, instead of retailers, become responsible for appointing metering coordinators. Based on further industry consultation and consideration, the Commission considers the proposed change would create new problems, the offsetting benefits would not be material, and that our recommendations address the issues raised by stakeholders within the current industry structure. More specifically, we find:

- implementing the proposed change would delay the acceleration program by approximately two years, or longer, due to complexities in implementation
- the disruption caused by the proposed change would create significant risks and uncertainty for the competitive metering industry
- the recommendations of this Review address the key issues stakeholders identified with the current industry structure, such as data access and challenges with multi-occupancy sites

## This final report delivers a package of reforms that can be implemented through a rule change process

23 The Commission has developed a preferred regulatory approach to support the accelerated deployment of smart meters and deliver universal uptake by 2030.

24 To promote a positive customer experience and social licence, we have developed safeguard measures and approaches to empower customers in the roll-out.

25 We have also identified opportunities for improving how smart meters get installed to enable efficient and cost-effective installation processes, reduced regulatory burden, and improve coordination among industry participants.

26 Finally, we have developed recommendations to allow additional smart meter benefits to be unlocked through greater access to smart meter data and services.

### Acceleration program to speed up smart meter deployments, delivering consumer benefits sooner

27 Based on stakeholder engagement and feedback, the Commission identified and assessed several regulatory mechanisms that could help deliver an accelerated deployment of smart

meters. If implemented, the recommendations will:

- set a clear target in the NER for the accelerated deployment of smart meters
- create a fit-for-purpose process to establish a pathway for replacing meters over the 2025–2030 acceleration period for each NEM region.

28 To achieve the goal of universal deployment by 2030, we recommend arrangements that create a new requirement for DNSPs to progressively retire the legacy meter fleet in the NEM over the period 2025 to 2030, and for retailers to replace meters within 12 months of when the meter was identified for replacement.

29 In designing a regulatory framework to deliver this outcome, we have sought to:

- create certainty, through strong obligations on industry to accelerate the installation of smart meters
- minimise the regulatory burden of this process on the AER and industry
- provide sufficient flexibility for different approaches to be adopted in each network area – balancing, for example, the achievement of geographical economies and the management of workforce constraints.

30 DNSPs would be required to develop 'Legacy meter retirement plans' (LMRPs) that schedule clusters of legacy meters to be retired and replaced each year of the five-year acceleration period (such as by postcode). DNSPs will be required to develop these LMRP schedules in consultation with key stakeholders.

31 We consider this approach is the most practical option, given there are far fewer DNSPs than retailers in each area, and DNSPs have detailed information on the existing legacy meter fleet (whereas retailers may not). DNSPs would be required to apply a regulatory objective and guiding principles, balancing retailer and other stakeholder views, to determine a deployment program pathway that broadly promotes the long term interests of consumers.

32 The AER would be required to confirm that DNSPs have met the minimum content requirements in the LMRP proposals, undertaken adequate consultation, and properly considered the regulatory objective and guiding principles before approving the LMRPs. The AER would have until 31 March 2025 to make its determinations so DNSPs can begin retiring the first tranche of legacy meters by 1 July 2025. This new regulatory process would have resource implications for the AER.

33 Retailers would have discretion on how and when they replace the meters each year of the acceleration program. We consider retailers have incentives to minimise the costs of the smart meter deployment program within these constraints, including coordinating with DNSPs and metering parties.

34 To promote transparency, retailers would be required to report on their annual performance and provide reasons for any divergence from their LMRP schedule to the AER — including explaining how they intend to get back on track if they are not compliant. The Commission recommends that civil penalties only apply to the final 2030 target. The AER's performance reporting would provide commentary on how the retailers are tracking from year-to-year, and provide a mechanism for regulatory oversight of the acceleration program.

35 Retailers would have the ability to seek amendments to their relevant LMRP schedules, if a LMRP is affected by a material error, change in circumstances or event. For example, a revision may be required when an ‘event’ occurs that was not anticipated, or that is beyond the reasonable control of the DNSP or retailer, that may negatively impact the retailer’s ability to meet the LMRP schedule and associated interim targets. A high materiality threshold would apply to trigger this LMRP revision process.

### Supporting a positive customer experience in the transition to smart meters

36 All parts of the sector have a role to play to help customers understand and navigate the complex changes that are happening. This takes clear communication of the benefits of smart meters from trusted sources of information. Strong partnerships and coordination between DNSPs, retailers and metering parties will be crucial to maintain consistent messaging and a seamless customer experience.

37 The following safeguards and information requirements are designed to build and maintain social licence. Without social licence, the smart meter acceleration program is less likely to realise the full potential of the benefits to consumers. For example, customers may increasingly refuse access to their properties, negatively associate smart meters with higher costs or be less willing to remediate their electricity boards when required.

#### Customer impact safeguards

38 The Commission considers new safeguards are required to manage customer risks associated with retailer decisions on how they pass on meter replacement costs to customers, as well as to provide customers sufficient notification and information regarding any changes to their retail pricing structure.

39 Proposed measures to safeguard customers from unexpected cost impacts during the acceleration period include:

- prohibiting retailers from charging upfront costs for meter replacements under the acceleration deployment program
- requiring retailers to provide their customers sufficient notice when transitioning to a different pricing structure – ie, 30 business day notification period, rather than the current requirement of five business days
- providing customers with additional information on how to understand and monitor their usage and manage change – including allowing the customer to request an estimate of what their historical bill would have been under the varied tariff.

40 We do not propose changes to the existing tariff structure statement process at the network tariff level, which we consider remains fit-for-purpose.

#### Empowering customers by providing them timely information

41 Customers should be provided with relevant and timely information before their metering installations are upgraded to smart meters. The Commission recommends:

- customers receiving an information notice from their retailer outlining the key information they need in plain-language
- development of a broader communication strategy including the likely development of a smart meter information website.

#### Supporting customers receiving a smart meter upon request and in a timely manner

42 For scenarios where the customer's request is not associated with a connection upgrade or a rooftop solar system installation, the NERR 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.

43 Clear and reasonable timelines need to be in place to support timely replacement of malfunctioning meters. We found that separate timeline requirements for the replacement of individual and 'family' failures are needed in order to support timely and efficient deployments. A 15 business day timeline should be provided for individual failures, while a default timeline of 70 business days coupled with a more clearly defined exemptions process would help support a more timely and orderly replacement of meters that are subject to family failures.

### Improving meter installation processes for better customer outcomes

44 Stakeholder feedback highlighted several process inefficiencies and pain points for customers and industry stakeholders in the deployment of smart meters.

45 In working with stakeholders, we identified adjustments to the metering framework to reduce barriers to installing smart meters and to enable their efficient and coordinated deployments. These measures include:

- **Reducing the number of customer notices for new meter deployments to reduce confusion**:[1] The Commission recommends that the number of notices a retailer must provide to a small customer when undertaking new meter deployments is reduced from two notices to one notice. This should reduce administrative burden and costs and enable greater flexibility in planning and deployments.
- **Consistent policy setting on opt-out:** The Commission recommends the removal of provisions in the NERR enabling customers to opt-out of a new meter 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 that address the multi-occupation issues.
- **Supporting better coordination for multi-occupancy scenarios**: The Commission recommends a 'one-in-all-in' approach to meter replacements to improve meter replacement efficiency and customer experience in scenarios where meters for customers

1 *new meter deployment* is a defined term in the NERR and excludes, among other things, meter replacements at the request of a small customer.

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.

- **Processes to support timely remediation of customer-site defects**: The Commission proposes to implement a customer notification and record-keeping process for circumstances where metering coordinators encounter customer-site defects preventing upgrades. 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.

46 The national energy framework has limited ability to address remediation issues. In our holistic consideration of this issue, we have identified a set of actions that could be considered by governments to help address the remediation issues in a more effective and equitable manner. They include considering:

- Financial support to encourage remediation, especially for vulnerable customers
- Undertaking a review of jurisdictional regulatory arrangements to identify and implement adjustments that could reduce the need for and cost of site remediation
- Undertaking a review of jurisdictional regulatory arrangements to enable metering parties to undertake minor remedial work.

47 Metering parties can also face barriers in accessing the meter installations in order to undertake replacements in instances where meters are secured by a DNSP locking system. According to metering providers, this is particularly prevalent in NSW. As site access rights are governed by jurisdictional arrangements, we suggest jurisdictions consider reviewing these arrangements, with a view to allowing contestable metering parties to appropriately gain access to such sites.

### Unlocking further benefits from smart meter data and services

48 Data and services provided by smart meters are expected to play a crucial role in helping the electricity system become more intelligent, responsive, efficient and customer-centric.

49 The evolving electricity system is becoming more active, complex and digitally enabled. This means that there is a growing need for customers and energy service providers to access more of the data and services generated by smart meters. Customers and service providers need the right information at the right time to make appropriate investment, operational and usage decisions.

50 We find that the current arrangements for accessing smart meter data are not suitable for delivering the current and future data needs of customers and energy service providers. These parties need better access to more of the data and services provided by smart meters.

51 To allow customers to get access to more of their data, we recommend implementing a

framework that provides customers access to their smart meter data in real-time free of direct charge, where they request it. A customer's authorised representative should also be empowered by the framework to access their real-time data.

52 Our proposed framework should be further developed before adoption to include clear rights to access for customers and their authorised representatives, clear definitions of real-time data, flexibility in how data is provided to customers and interoperability considerations.

53 We consider the proposed framework underpinned by customer choice would allow customers to get more information about their usage and have more control over their data. We expect it will promote competition, support the coordination of customer devices, and foster the development and use of new and innovative services and product offerings for customers.

54 To help DNSPs get efficient access to power-quality data (PQD) from smart meters, we recommend implementing a Basic PQD access framework that provides DNSPs access at no direct cost. This access framework will outline the inclusions of basic PQD, corresponding obligations on relevant parties to provide basic PQD and the method and service levels for exchanging the data. We envisage providing DNSPs regulated access to basic PQD will support efficiency and certainty of access to data that is crucial for several uses, such as:

- **Improving customer safety outcomes:** by enabling DNSPs to detect neutral integrity faults and voltage excursions at the customer premises earlier, so they can be addressed before they pose safety risks to customers.
- **Supporting CER integration:** by enabling greater visibility of the Low Voltage (LV) network. This will support initiatives such as Dynamic Operating Envelopes (DOEs) to allow more customer CER to connect and export without unnecessary constraints or investments.

55 Other services provided by smart meters, such as, more advanced PQD and on-demand services, can be procured by the service users from the metering parties through commercial negotiations. Stakeholders did not raise concerns regarding efficiently accessing these services.

### Supporting ongoing accuracy of the metering fleet

56 The requirements for undertaking inspections of smart meter installations need to be clarified. To support the efficient inspections of smart meters, we recommend clarifying that MCs need to outline their meter inspection practices in a metering asset management strategy (MAMS) for AEMO assessment and approval. We also recommend that AEMO develops a guideline for assessing and approving MAMS, following set principles and objectives.

57 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. Removing regular testing and inspection for legacy meters would 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. It would also reduce the complexity of developing LMRPs.

### Next steps

58 We consider the proposed package of reforms recommended above are robust and reflect the very significant input and feedback we have received from a broad group of stakeholders.

59 The goal is to achieve universal penetration of smart meters in the NEM by 2030. The subsequent rule change and other regulatory processes required to implement the recommended reforms – including AER approval of LMRPs proposed by DNSPs following industry consultation – would need to be completed by 31 March 2025.

60 The Commission is committed to prioritising these reforms should a proponent submit a rule change to us.

# CONTENTS



## APPENDICES

# TABLES



# FIGURES

# 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 to determine whether changes are required to improve the efficiency and effectiveness of the regulatory framework for metering services.[2] 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 November 2022 draft report, September 2021 directions paper and December 2020 consultation paper.[3]

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

To guide the Review, 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 through their benefits to individual consumers, and by enabling a more efficient and lower-cost energy system. 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 the barriers consumers face to realise the benefits.

The Review has focused on four areas, which were informed by feedback received from stakeholders after the consultation paper:

- **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 accessing smart meter data, and barriers to the delivery of services enabled by smart meter data, should be minimised.
- **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 that smart meters enable.

2 AEMC, *Expanding competition in metering and related services*, 2015.

3 Available from https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

- **Roles and responsibilities** | Facilitate cooperation, coordination, and communication to improve the consumer experience and maximise benefits.

## 1.2 We have consulted with stakeholders throughout the Review

The consultation paper for the Review outlined our approach to examining the metering regulatory framework's current state, and barriers to realising potential benefits. Our approach was informed by prior projects, stakeholder surveys, and interviews – providing a rich understanding of stakeholders' expectations and experiences.

We established a reference group of over 50 participants to collaborate with stakeholders, formulate solutions, and incorporate advice into our decision-making processes. Having a wide range of stakeholder organisations enabled us to progress issues analysis and policy development in the four areas listed in section 1.1.

The Commission engaged SEC Newgate Research in 2021 to complete a study of consumer attitudes towards smart meters.[4] This diverse study of residential and small business customers provided crucial insights into the Commission's directions paper, including:

- Customers were most interested in tangible smart meter benefits, such as ways to save on bills, accurate meter reads, and electrical safety.
- Where customers had concerns about smart meters, they were usually related to potential costs associated with new tariff structures, smart meter installation, or remediation.
- Consumer awareness of smart meters was somewhat low, and customers wanted more information on how they could benefit from a smart meter when receiving one.

The Commission's September 2021 directions paper detailed the key issues preventing achievement of a critical mass of smart meters, thereby impeding the realisation of consumer and system benefits. With extensive stakeholder consultation – including reference groups, unilateral meetings, and written submissions – we identified the direction of reforms for the metering framework.

We published a draft report in November 2022.[5] Our draft recommendations included a target of 100 per cent smart meter penetration by 2030, necessary measures to accelerate deployment, and supporting changes to the regulatory framework that would address barriers to a faster deployment program. These draft recommendations reflected a highly collaborative consultation process with significant inputs from a broad range of stakeholders.

The Commission maintained a collaborative approach in the development of this final report, which reaffirms the target of 100 per cent smart meter deployment by 2030. Stakeholder input has informed our detailed final recommendations, changes to some draft recommendations, and recommendations on sub-issues that we have not previously addressed.

4 SEC Newgate Research, *AEMC metering review - An assessment of consumer experiences relating to smart electricity meters and their competitive roll out within the National Electricity Market, Full research report* September 2021.

5 The Review was paused between November 2021 and April 2022 due to resourcing limitations.

Throughout the Review, we received over 160 submissions from a broad range of stakeholders including consumer groups, retailers, DNSPs, metering parties, meter manufacturers, market bodies, jurisdictional regulators, government officials, industry bodies, technology companies, unions, investors, and individuals. We held bilateral and multilateral meetings with many stakeholders at all stages of the Review to gain a deeper understanding of their perspectives and experiences. Stakeholders' feedback has been instrumental in assisting the Commission to determine key issues with the existing framework, and to develop feasible solutions. The Commission has addressed and relied on stakeholder feedback through the report. However, some issues raised by stakeholders were beyond the remit of the Review, or are being addressed through other reforms.[6]

## 1.3 The Review's recommendations contribute to the national energy objectives

In conducting reviews, the Commission must have regard to the relevant energy objectives.[7] For this Review, the relevant energy objectives are the national electricity objective (NEO) and the national energy retail objective (NERO).

The NEO is:

> *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:*
>
> 1. *price, quality, safety, reliability and security of supply of electricity; and*
> 2. *the reliability, safety and security of the national electricity system.*

The NERO is:

> *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.*

### 1.3.1 How we have applied the NEO and NERO to our recommendations

We have identified the following criteria to help assess which recommendations are likely to better contribute to achieving the NEO and the NERO:

- Outcomes for consumers
- Implementation considerations
- Innovation and flexibility
- Principles of market efficiency
- Safety, security and reliability

6 Energy and Water ombudsmen suggested the inclusion of metering service providers in Ombudsman schemes. This would require changes to the NERL. Several stakeholders suggested the Review should enable appropriate metering arrangements for street lights. We note that this issue is being progressed through the rule change for *Unlocking CER benefits through flexible trading.*

7 Section 32 of the NEL and section 224 of the NERL.

- Decarbonisation.

A brief explanation of these criteria and our reasons for choosing them are set out in section 1.2.2 of the draft report.[8] Our proposed reform agenda outlined in this report promotes the NEO and the NERO. The acceleration target and supporting reforms are driven by the long-term interests of consumers. An assessment of the proposed reforms against the assessment criteria is outlined in section 2.4.

The Commission has undertaken regulatory impact analysis to evaluate the impacts of the various policy options. Appendix H outlines the methodology of the regulatory impact analysis.

### 1.3.2 The new energy objective will apply to any subsequent reforms

In May 2023, Energy Ministers approved amendments to the national energy laws to implement their previous decision to incorporate an emissions reduction component into the NEO, NERO, and National Gas Objective.[9]

The legislative process to introduce an emissions reduction component into the national energy objectives is currently underway, and is expected to be completed in September 2023.[10]

In developing these final recommendations, the Commission has been guided by the current NEO and NERO. However, the Commission considers these recommendations will remain appropriate in light of the changes to the NEO and NERO. This is because the recommendations will, if implemented, promote emissions reduction through better integration of CER and through demand shifting to periods of higher renewable energy generation.[11]

Any rule change requests stemming from this Review would need to be considered with regard to the new energy objectives.

## 1.4 How this report is structured

The final report is structured as follows:

- Chapter 2 explains why the Commission recommends the target of universal take-up of smart meters by 2030 in NEM jurisdictions – including our vision for the crucial role smart meters will play in the future, and identifies measures to improve efficiencies and reduce delays. It also outlines our analysis of the reforms against the relevant assessment criteria.

8 AEMC Review of the regulatory framework for metering services, draft report, 3 November 2022, pp. 3-4.

9 Department of climate change, energy and environment and water, 2023. Energy and climate change ministerial council meeting communique, 19 May 2023.

10 The Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Bill 2023 was introduced into South Australian Parliament on 14 June 2023.

11 See sections 2.1.5 and 2.4 for further details.

- Chapter 3 provides a summary of the Commission's 21 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, and the basis for our final recommendations.

- Appendix A (Acceleration and safeguards) outlines the target of universal take-up of smart meters by 2030 in NEM jurisdictions and the mechanism for acceleration. Mechanisms for safeguarding customers during acceleration are also included here.
- Appendix B (Industry structure) outlines the Commission's consideration of an alternative industry structure proposed by stakeholders and our decision to retain the current structure.
- Appendix C (Improving Customer experience in metering installations) outlines our recommendations to improve customer experience by supporting improved customer awareness, explicit rights for customers to get a smart meter and improved timeliness of installations.
- Appendix D (Reducing barriers to installing meters) outlines our recommendations to address problems with the current framework that have created inefficiencies and led to poor customer experiences.
- Appendix E (Access to Power Quality Data) outlines new access arrangements for exchanging Power Quality data between MCs and DNSPs.
- Appendix F (Access to Real-time data) outlines our recommendations to enable consumers to access near real-time usage data.
- Appendix G (Fit-for-purpose testing and inspection requirements) outlines recommended changes to create a fit-for-purpose meter testing and inspection
- Appendix H (Quantifying impacts) responds to stakeholders' feedback on the cost-benefit assessment prepared by independent consultant Oakley Greenwood, and provides a detailed summary of a new extension to the analysis.
- Appendix I provides legal drafting instructions to assist the implementation of the final recommendations.

# 2 THE NEED FOR REFORMS TO THE METERING SERVICES FRAMEWORK

The Commission's key recommendation is the target of universal smart meter deployment in the NEM by 2030. A higher and faster take-up of smart meters and greater data access are needed to realise many benefits to consumers. A 2030 timeframe is likely to be the earliest time that industry can realistically achieve. This recommendation would have the most impact in New South Wales, the Australian Capital Territory, Queensland, and South Australia. Tasmania has an acceleration program in place with a 2026 target. Victoria has already achieved a near-universal take-up of smart meters.

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 are increasingly investing in consumer energy resources (CER) — such as solar panels and, increasingly, battery storage and electric vehicles. The rapid take-up of CER has already delivered significant benefits to households. The Commission's overarching reform objective is to develop the framework for metering services so that it remains suitable for an energy system in transition, and is best able to support the current and future needs of customers and the electricity system.

A target of universal smart meter take-up by 2030 will support the transition to the future energy market (section 2.1). Progress in deploying smart meters has been slow to date, and less efficient than it could be. Outside of Victoria, the average smart meter take-up 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 take-up is achieved, and full deployment of smart meters may not occur until after 2040.[12]

The Commission has identified several opportunities to enhance the current metering arrangements in order to accelerate progress and improve customer outcomes (section 2.2). 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 accelerate replacements will result in significant net benefits to customers (section 2.3). We consider the reforms and actions recommended in this Review will promote the long-term interest of consumers (section 2.4).

## 2.1 A target of universal smart meter take-up by 2030 will support the transition to the future energy market

Smart meters are necessary to transition the current electricity system to one that is smarter, more integrated, and takes full advantage of the technological developments in metering (section 2.1.1).

12 Based on modelling by Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

Meters are an enabler, forming the platform for accurate data collection. Smart meter data enables:

- the provision of innovative services to customers by parties including emerging businesses
- customers to access potentially cheaper tariffs from retailers, such as through solar soaker tariffs, allowing customers with and without CER to benefit
- DNSPs to run their networks more efficiently, and to develop strategies that allow more CER to be connected to the grid
- decarbonisation, through better integration of CER and demand shifting to periods of high renewable energy generation.

### 2.1.1 The 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 only 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.

This future relies on data. Smart meters turn power into valuable information that can reduce costs, increase reliability, and open up a diverse range of opportunities for innovation. For example, better information can:

- improve the efficiency of network operation, use, and planning to unlock the value of lower cost CER integration
- enable demand management and response to meet changing conditions
- improve demand and supply forecasting
- personalise consumer insights, tips, or actions
- maximise responsiveness to cost-reflective tariffs and dynamic pricing
- stimulate innovation in products and services.

Bringing forward the installation of smart meters will provide customers with earlier access to these benefits. Accelerating smart meter deployment also reduces the overall costs of installation. Although some investments will need to be made earlier, installation costs can be reduced by rolling out smart meters more rapidly and in an efficient sequence (see Section 2.2.3) — making all customers better off.

Smart meters enable consumers to better participate in the energy system transition. We expect that more data-driven applications and products will become available in the longer term. These applications and products, as shown by the SEC Newgate research completed for the directions paper, are material drivers of customer sentiment.[13] Accelerating the deployment of smart meters enables earlier delivery, while facilitating a more open and flexible energy market.

13 SEC Newgate Research, *AEMC Metering Review - An assessment of consumer experiences relating to smart electricity meters and their competitive roll out within the National Electricity Market*, report, pp. 66, 70.

New business models are emerging. Collective engagements, such as virtual power plants (VPPs), offer small and large consumers opportunities to participate in new energy markets. There are significant industry trials and rule change proposals focused on integrating CER into the NEM and creating new value streams to maximising the benefits of household CER investments.

Consumers, DNSPs and competitive businesses must have access to smart meter data in order to generate the most value from the investment in metering. For example, networks can use granular power quality data to improve the efficiency of network operation and planning. Residential and business customers can also manage their energy usage more effectively — either independently or through a third-party service — if they have better visibility of their consumption. Without widespread, low-cost, timely access to data, many of the benefits available from smart meters will not be realised.

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

Universal deployment of smart meters will allow customers to better manage their energy bills by choosing the tariffs and retailers they want, and to change behaviour when they are better off from doing so.

A higher take-up 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 also support greater competition in the electricity retail market.[14]

Smart meters create opportunities for greater data sharing, promoting competition, innovation and more targeted energy policies. Smart meters facilitate time based prices. Consumers can control their appliances or vehicle charging, for example through a mobile app or hub-based service, to take advantage of times when energy prices are low.

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

Innovative third-party service providers can help customers to automate and optimise household devices to minimise customer bills and maximise the value of their CER investments. This can be realised through increasingly affordable home energy management systems that can respond autonomously to price signals while minimising impacts on people's day-to-day lives. Easy, continuous, and interoperable access to smart meter data in real-time, as proposed in this Review, could materially contribute to these new and emergent use cases — unlocking high-potential long-term innovations.

When customers are well-informed about these smart meter benefits, they are more likely to make use of them. SEC Newgate's customer research, completed for this Review, found that

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

many customers wanted more information about how to make the most of their smart meter.[15] Consumer awareness of the benefits can be improved through multiple strategies — such as public communications or more detailed notices provided in the lead-up to smart meter installation.

### 2.1.3 Smart meters will enable the future grid

Smart meters provide 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. They can also enable retailers to reduce their operational costs through improved risk management and a better understanding of customer usage.

DNSPs such as SA Power Networks in South Australia are beginning to offer 'solar soaker' tariffs that allow households to consume electricity in the middle of the day at very low or even zero cost. These developments have significant customer and stakeholder support across jurisdictions.

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, reducing the need for expensive future network augmentation.

Innovative network approaches that support more CER being 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. DNSPs can also better optimise voltage regulation, so that CER is constrained off less often.

For market participants, such as retailers, smart meters can help realise the benefits of more flexible demand and generation and thereby help them better manage their risks and costs. Approaches such as dynamic control of their customers' hot water load can help retailer manage their wholesale exposure and costs by providing them with some control over their demand. More up-to-date and granular information about their customer's usage could also help retailers better manage their risks and costs.

### 2.1.4 The acceleration program will allow all households to access smart meter benefits earlier

While the increasing take-up 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 less able to benefit from the transition because they cannot invest in CER, or actively participate in CER markets.

The Commission considers that reforms and changes to the regulatory framework should benefit all consumers. Smart meters will enable customers without CER to benefit from the

15 SEC Newgate Research, *AEMC Metering Review - An assessment of consumer experiences relating to smart electricity meters and their competitive roll out within the National Electricity Market*, report, pp. 66, 70.

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 previously submitted:[16]

> 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.

Non-CER customers will also benefit from better investment decisions by DNSPs, and lower generation costs, facilitated by data from smart meters.

### 2.1.5 Smart meters are essential infrastructure for the energy transition

Smart meters are a critical technology for the clean energy transition. They enable a range of benefits that can help to reduce energy consumption, improve grid flexibility, and decarbonise the energy supply.

We recognise that decarbonised, affordable and reliable energy is a key enabler of economic growth and improved consumer living standards. Decarbonisation is a significant focus for the energy sector. State and Commonwealth governments have adopted a range of policy initiatives to meet this objective. Investors increasingly consider decarbonisation in environmental, social and governance criteria in their decision-making processes.

Household investment in CER, such as rooftop solar and batteries, reflects environmental concerns. The accelerated deployment of smart meters, coupled with the proposed enabling reforms for data access, will support the efficient integration of CER. As previously mentioned, smart meters will enable innovative tariffs and allow networks to deploy innovative technologies such as dynamic operating envelopes.

A high take-up 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 take-up of electric vehicles. The accelerated smart deployment will also support the efficient integration of EVs into the electricity system by enabling a better understanding of their impact on the grid and the use of potential new tariffs developed for EV customers.

16 ECA submission to directions paper, p. 2.

## 2.2 The regulatory framework for the provision of metering services can be improved

The Commission introduced the current metering framework through the *Competition in metering* rule change in 2015 to encourage commercial investment in smart meters and associated services. Retailers played a key role in shaping the current metering framework. The rule required a smart meter to be installed for small customers on a new and replacement basis. Retailers were provided with the ability to undertake new meter deployments.[17]Small customers could also request a smart meter. Smart meters are also required for solar PV installations.

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 was a clear benefit.

We acknowledge the performance of the metering framework and market outcomes have not met the expectations set out in the original rule. For example:

- **Too slow**: 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 barrier — which appears to have been driven by misaligned incentives of market participants and the complexity of the framework (section 2.2.1).
- **Critical mass**: The deployment of smart meters in the NEM has mainly been driven by consumer requests to install solar PV systems and by new connections. Retailer-initiated smart meter programs have been minimal in most jurisdictions. Economies of scale are required for market participants to justify investment in innovative services. Where smart meters have been installed, the scope of services offered to consumers has been narrow. This means some consumers without CER are not seeing high enough direct benefits to justify requesting a smart meter (section 2.2.2).
- **Misaligned incentives**: Smart meters provide indirect benefits to other households, DNSPs, retailers and the system operator, AEMO. These broader benefits are not necessarily factored into customer decisions to request a smart meter. Also, retailers incur most of the costs of installing smart meters. This means there is a risk that the 'private' benefits to customers and retailers of smart meters will be significantly less than the social benefits. This may have led to an inefficient level of investment in metering infrastructure from an economy-wide perspective (section 2.2.3).
- **Process inefficiencies**: Significant inefficiencies in the installation process led to higher customer metering unit costs. Ombudsmen and AER complaint data highlights several implementation issues, including systematic installation delays (section 2.2.4). Installing meters in certain scenarios, such as where a customer is on a shared fuse or has a site defect, has been challenging for metering parties and customers.
- **Poor outcomes for customers:** Customers receive limited information about meter replacement, which impacts the customer experience and social licence. Further,

17 'New meter deployment' is defined in rule 3 of the NERR and excludes meters replaced at the request of the customer, or replaced due to maintenance or malfunction.

customers are not sufficiently protected from unexpected tariff changes triggered by metering upgrades (section 2.2.5).

- **Lack access of access to data provided by smart meters:** Under the current regulatory framework exchange, sharing of data is limited. Greater access to smart meters could be one way to maximise the net value that consumers receive from their investment in smart metering (section 2.2.6).

### 2.2.1 Smart meters are not being rolled out fast enough

Stakeholders have told us the deployment of smart meters has been piecemeal, ad hoc and slower than expected. Regulatory barriers include:

- fragmented jurisdictional regulatory frameworks for smart meter installation and services — whereby some state or territory governments have prohibited potential benefits to retailers (such as remote disconnections)
- strict regulatory compliance requirements and operational inefficiencies in the meter malfunction exchange process — with limited incentives for retailers to initiate family failure replacements due to poor site compliance and a minority of customers refusing the upgrade
- expensive and sometimes unnecessary physical field assessments before meter installations can take place
- site access issues — especially for 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.

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

Stakeholders have highlighted that the realisation of the benefits of new and innovative services is dependent upon a critical mass of smart meters and sufficient level of data sharing — whereby economies of scale are required for market participants to justify further investments in innovative customer services.

Many of the direct benefits to DNSPs, such as LV network optimisation, and retailers — which flow through to customers — also rely on a minimum level of take-up of smart meters. ENA's submission to the directions paper provides an indicative summary of services DNSPs can provide, and the minimum and optimal data take-up required to deliver benefits to customers.[18] DNSPs demonstrate that these services may also require more explicit data access or a geographically significant spread of smart meters before realising consumer benefits.

Further, retailers have faced low incentives to undertake new meter deployments. The direct benefits to retailers may not always cover the initial installation costs of smart meters. Our

18 ENA submission to directions paper, pp. 20–23.

recommendation to accelerate the deployments would help overcome the slow rollout of smart meters and the lack of incentives faced by retailers and customers.

### 2.2.3 Incentives for individual households and retailers 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 EVs
- providing consumers with visibility and control of their electricity consumption and costs — such as reduced estimated meter reads, and more access and pricing options
- 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, 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.

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.

Further, the expected competitive pressures and commercial incentives on retailers to proactively deploy smart meters have not been strong enough — in part due to low take-up rates limiting retailers' ability to achieve economies of scale (as discussed above). Incentives for retailers to accelerate meter take-up are not clear when the (private) benefits may not exceed the costs incurred. Although DNSPs would benefit from greater take-up of smart meters, DNSPs currently bear none of the costs or logistic and administrative burden.

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. Bringing forward the installation of smart meters will achieve process efficiencies and economies of scale, increasing net benefits to consumers. While some costs will be incurred earlier, they will be lower in the future and overall. Customers will also be able to access benefits sooner, including being able to better manage their energy bills by choosing to switch tariffs or change behaviour when they are better off doing so.

### 2.2.4 Process inefficiencies are leading to higher meter installation costs

We have found that complex relationships between parties, unclear objectives and separation of responsibilities, geographical challenges and incentive problems have caused process inefficiencies. This includes legacy electrical and installation issues that are not within the NEL's scope to address, but which are nonetheless impacting meter deployment.

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.

Stakeholders have also identified inefficiencies affecting meter installations in practice. These include coordination challenges at premises with shared fusing, site defects requiring remediation before a meter can be installed, and onerous notice requirements on retailers. In particular, stakeholders noted that meter upgrades triggered by family failures are often subject to lengthy delays which are not managed effectively under the current framework. These obstacles to meter installation need to be addressed so that the accelerated deployment can reach the highest achievable smart meter penetration. We are recommending a series of improvements to the metering installation process to help overcome these barriers.

### 2.2.5 Customer experience when meters are replaced can be poor

Current process requirements for installing a new meter may lead to a poor customer experience.

Customers may lack the necessary information to make informed decisions and benefit from smart metering upgrades. Appropriate information needs to be provided to customers prior to deployments. Customers can also face delays in getting a new meter and may not be able to obtain a smart meter under certain circumstances.

Customers may also face unexpected changes to their bills due to automatic tariff-reassignment policies coupled with inadequate notification obligations. There is also no explicit protection for customers from potential up-front lump sum charges for meter deployments. To address customer experience issues, we are recommending measures to enhance the information available to customers and protect customers from unexpected costs.

### 2.2.6 There are barriers to accessing data from smart meters

The potential value of smart meters is not being fully realised under the current regulatory settings. We find there is need to improve sharing of data between industry participants, customers and their service providers by improving the standardisation of data structures and exchange methods, as well as ensuring fair, reasonable, and non-discriminatory data access. Key use cases, such as utilising smart meter data for user-friendly apps that give consumers real-time visibility of their energy usage, are not widely offered.

The current regulatory framework lacks sufficient access for customers and the broader industry participants to smart meter data, preventing it from being widely shared and used. This issue is relevant for access to basic power quality data and real-time data from smart meters. Data could be considered non-rivalrous, meaning that it can be reused, shared, and aggregated without losing its original value. Reusing, sharing, and aggregating data can generate economies of scale and scope, or network effects as the data is repurposed.

We consider that the lack of sufficient access to smart meter data is limiting the efficient and safe operation and investment in networks, the development and use of innovative services and customer access to useful data.

To improve access to smart meter data, we are recommending improved access frameworks for access to power quality data and real-time data for DNSPs and customers respectively.

## 2.3 Independent cost-benefit analysis supports the need for an 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). The assessment considered the economic costs and benefits of an accelerated deployment of smart meters, targeting 2030 compared to the status quo of replacing legacy meters on a 'new and replacement' basis. The report is available on the project web page at: [aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services](aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services).

Oakley Greenwood found that 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). The net positive result holds even if only a limited set of highly achievable 'non-contingent benefits' is included, although the size of the net benefit is reduced in this case. The non-contingent benefits are those 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).

That is, bringing the deployment of smart meters forward will achieve process and scale efficiencies that increase the net benefits to consumers. While some costs will be incurred earlier, they would be lower in the future and overall thanks to acceleration. A more detailed summary of the Oakley Greenwood cost–benefit assessment is provided in Appendix F of the draft report, including the underlying assumptions applied by Oakley Greenwood. The Commission also further considered the timing of costs and benefits under an accelerated deployment and the implications for retailers and customers.

Since the draft report, the Commission has engaged Oakley Greenwood again to test the sensitivity of the cost–benefit assessment to higher metering costs. The Commission considered it would be prudent to do so because feedback from industry suggests metering costs can vary, and this is a key input to the cost–benefit model. The sensitivity analysis found the net benefits remain positive even if the costs of smart metering are increased to a level that industry discussions suggest is possible, although not certain. This indicates the original cost–benefit analysis — which remains the primary result — is resilient to uncertainty in costs. An addendum to the report is available on the project web page and a more detail summary of the additional results is provided in appendix H.

## 2.4 A new reform agenda promotes better customer outcomes

The Commission has developed a package of reform recommendations to both address the need for change, and capitalise on the opportunity to achieve greater efficiencies in the smart meter deployment program. Our recommendations (outlined in chapter 3:

- **Improve customer outcomes:** Smart meters are crucial to modernise the energy system, accommodating future technologies and innovation. After considering varying consumer preferences and outcomes, our recommendations aim to improve customer outcomes — particularly by encouraging universal smart meter adoption by 2030 and introducing a new regulatory process for deployment. Accelerated deployment benefits all consumers provides early access to benefits. Safeguards protect against upfront charges and unforeseen tariff adjustments. Enhancements in the customer experience involve the provision of essential information before smart meter upgrades, grant customers the ability to request a smart meter, and refine the timing for replacing malfunctioning meters.
- **Support market efficiency:** Accelerated deployment promotes economies of scale and efficiency gains lowering meter installation costs. Our supporting recommendations reduce barriers, regulatory burden, and information asymmetry between consumers and market participants. Oakley Greenwood's analysis shows that full deployment by 2030 leads to economic gain for consumers (see above). Our proposed LMRP mechanism ensures an efficient rollout strategy. Further supporting measures seek to minimise transaction costs, enhancing market efficiency.
- **Promote innovation and flexibility:** The metering framework encourages innovation for new services. Our recommendations foster innovation by accelerating the deployment of smart meters, which in turn provides the data necessary for customers to make informed choices, and for retailers and service providers to use in developing and offering innovative products. A faster rollout also allows network operators to better manage their networks through innovative methods. Increased visibility of power quality data allows DNSPs to explore methods for getting more out of their existing assets, minimising new expenditure and increasing CER hosting capacity.
- **Support decarbonisation of the electricity system:** Smart meters make an important contribution to energy system decarbonisation. Smart meters facilitate shifting demand to periods of excess renewable generation, allowing consumers to take advantage of low energy prices through products such as solar soaker tariffs. Smart meters are expected to play a pivotal role in supporting the efficient integration of increasing levels of CER by providing data that, for example, helps networks to maximise hosting capacity of rooftop solar PV and minimise augmentation expenditure requirements for electric vehicles, and helps consumers to optimise battery and appliance

operation. The operation of the NEM is likely to become more complex and challenging with higher penetration of variable renewable energy. Smart meter data is necessary for an orderly transition to net zero because it empowers consumers, network operators, market participants and service providers.

- **Addresses key implementation risks:** In developing our recommendations, we considered the impact on and variability of costs, the timing of benefits, and complexities in regulatory arrangements. We also consulted extensively on whether a 2030 target is achievable. Our consideration of these factors and associated risks informed our recommendations, resulting in a balanced implementation strategy that aligns with industry capabilities, minimises disruptions, and maximises the potential for customers to realise benefits. We have had regard to the potential financial impacts for different industry participants across the electricity value chain and customers. We are satisfied that the costs impacts of an accelerated deployment are likely to be relatively modest. We have also made recommendations to reduce some of the practical barriers to smart meter installation.
- **Promote safety, security and reliability of the electricity system:** Smart meters contribute to the safety and security of the distribution system by providing better data accessibility and enabling faster responses to outages or safety issues. Our recommendations support these improvements by deploying enabling technology faster. Upgrading the small customer meter fleet will allow retailers to provide more efficient, accurate, and reliable metering services with increased functionality. Measures such as addressing site defects, improving access to power quality data, and ensuring appropriate replacement timeframes for shared fusing sites and malfunctioning meters contribute to maintaining a safe, secure, and reliable distribution system — contributing to overall system stability, and enhancing consumer confidence and system resilience.

# 3 RECOMMENDED METERING REFORMS

Chapter 2 explains why the Commission recommends a target of universal take-up of smart meters by 2030 in NEM jurisdictions. In it, we set out our vision for the crucial role smart meters will play in the future, and identify issues that have led to inefficiencies, poor customer experience and a lack of access to smart meter data.

The Commission makes 21 recommendations in order 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 increase access to smart meter data.

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, and the basis for our recommendations. The drafting instructions (DIs) supporting the implementation of these recommendations can be found in appendix I.

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

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| **Setting a target and mechanism to accelerate the deployment of smart meters across the NEM** | | | |
| 1 | **Universal deployment of smart meters by 2030.**<br>The Commission recommends a target of universal take-up of smart meters by 2030 in NEM jurisdictions. We consider a five-year acceleration period from July 2025 to June 2030 promotes timely deployment of smart meters, is feasible, and allows retailers to efficiently manage resources. This view is based on extensive engagement with stakeholders and analysis of industry data.<br>This recommendation applies to New South Wales, the Australian Capital Territory, Queensland and South Australia. | A | 1 |
| 2 | **New regulatory arrangements to deliver smart meters for customers**<br>The Commission recommends regulatory arrangements that create a new requirement for DNSPs to progressively retire the legacy meter fleet in the NEM, and for retailers to manage replacement of these retired meters. This is Option 1 from the draft report, the Legacy meter retirement plan (LMRP) approach, which was supported by | A | 1 and 2 |

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| | a large majority of stakeholders. | | |
| 3 | **Retailer performance reporting and compliance to promote transparency and create regulatory oversight**<br>The Commission recommends that retailers be required to report on their annual performance against the LMRP to the AER and that civil penalties apply to non-compliance with the final 2030 target. Performance reporting would include:<br>• information on meter installations completed and attempted each year<br>• reasons for any divergence from their LMRP schedule<br>• where applicable, outlining how they intend to get back on track if they are not compliant<br>We appreciate that, in some instances, it may not be possible for the retailer to complete a meter exchange (either on time, or at all) for reasons beyond their control, and have provided a mechanism for reasonable circumstances to be considered. | A | 2 |
| 4 | **New customer safeguards as part of the transition**<br>The Commission recommends new safeguards to manage customer impacts associated with the installation of a smart meter. In our view, these are crucial considerations to support social licence of the smart meter acceleration program.<br>The Commission recommends:<br>1. prohibiting retailers from specifically charging upfront costs for meter replacements under the acceleration program<br>2. requiring retailers to provide their customers sufficient notice when transitioning to a different tariff structure – ie, a 30 business day notification period<br>3. providing customers with additional information on how to understand and monitor their usage, and how to manage change – including allowing the customer to request an estimate of what their historical bill would have been under any new tariff structure. | A | 3 and 19 |

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| 5 | **No change to the current industry structure**<br>The Commission recommends no changes to the current industry structure.<br>Retailers and metering parties will remain responsible for metering services for small customers.<br>The recommendations 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. | B | Not applicable. |
| **Reducing barriers to make deploying smart meters easier** | | | |
| 6 | **Removal of the existing opt-out provision under current framework and no opt-out provisions for accelerated deployments**<br>The Commission recommends the removal of provisions enabling customers to opt-out of new smart meter deployment under standard retail contracts. Customers would not be forced to remediate site defects.<br>Retaining an opt-out provision for new meter deployment (as defined in the NERR, rule 3) is inconsistent with the broader policy objective of accelerating deployment, and would create confusion.<br>Similarly, introducing provisions for customers to opt-out of acceleration would impact the efficiency of accelerated deployment. | D | 20 |
| 7 | **Reduced number of retail notices**<br>The Commission recommends that retailers only provide one notice for a new meter deployment (as defined in the NERR, rule 3), with expanded information requirements.<br>This would reduce administrative burden and costs, and enable greater flexibility, planning and coordination – likely without negative customer impacts. | D | 21 |
| 8 | **Introduction of a process to encourage customers to remediate site defects, and to track sites that need remediation**<br>The Commission recommends implementing a customer | D | 4, 5, 22 and 23 |

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| | notification and record- keeping process for circumstances where MCs encounter customer site defects. | | |
| 9 | **Arrangements to better support vulnerable customers who need to carry out site remediation**<br><br>The Commission recommends 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. | D | Not applicable |
| 10 | **Governments consider a review of jurisdictional/DNSP regulatory arrangements to:**<br>• **identify and implement adjustments that could reduce the need for, and cost of, site remediation**<br>• **enable metering parties to undertake minor remedial work without requiring prior customer approval.**<br>The NER and NERR are unable to address issues associated with remediation of a customer's electrical installation.<br><br>Addressing remediation issues will increase the proportion of sites that can receive a smart meter. | D | Not applicable |
| 11 | **Governments consider a review of jurisdictional arrangements to allow contestable metering parties to appropriately gain access to sites currently secured by a DNSP's locking system.**<br><br>This is aimed at reducing instances where meters can't be replaced, or where additional costs are incurred, due to site access issues. | D | Not applicable |
| 12 | **Improve industry coordination and minimise negative customer impacts in shared fusing installations**<br><br>The Commission recommends adopting 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. | D | 6 |
| **Improving the customer experience when they get a smart meter** | | | |

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| 13 | **Requirements on retailers to provide small customers important information in a clear, streamlined, and consistent way before any smart meter upgrade**<br><br>The Commission recommends new obligations for providing up-front and customer-friendly information to customers to support the deployment of smart meters, empowering customers to make the best use of their meter upgrades. | C | 24 and 25 |
| 14 | **Development of a communications strategy to support the accelerated deployment of smart meters.**<br><br>This measure will support establishing the social licence required for both the accelerated deployment and for the energy transition more broadly. | C | Not applicable |
| 15 | **Requirements on retailers to accept and deliver on customer requests for a smart meter**<br><br>The Commission recommends that customers be able to request and receive a smart meter for any reason. | C | 26 |
| 16 | **Implementation of appropriate replacement timeframes for meter malfunctions**<br><br>The Commission recommends allowing a longer replacement timeframe for family failures than for individually identified malfunctions. | C | 7 |
| 17 | **Clarifications to the malfunctions exemptions process currently administered by AEMO**<br><br>The Commission recommends that the exemption process be amended to clarify that:<br>• MCs must provide AEMO with a rectification plan as part of their request for an exemption<br>• AEMO must consider certain factors (see section C.3.7) in assessing an exemption request.<br><br>The Commission recommends improving compliance with the timeframe requirements for replacing malfunctioning meters in order to prevent a backlog of malfunctioning meters in AEMO's exemption register. | C | 8 |
| **Opportunities to unlock further benefits for consumers and other parties** | | | |

<table>
<tr><th>NO</th><th>FINAL RECOMMENDATION</th><th>APPEN-DIX</th><th>DI NO</th></tr>
<tr><td>18</td><td>Introduction of arrangements for better access to power quality data<br><br>The Commission recommends that metering service providers be required to collect, process, and deliver a basic level of PQD to the LNSP in a standard and efficient way. Basic PQD should be standardised under the framework and provided to LNSPs at no direct charge.<br><br>Participants would commercially negotiate more advanced levels of PQD where they are desired.</td><td>E</td><td>9 -14</td></tr>
<tr><td>19</td><td>Establishment of an enabling framework for customer access to real-time data<br><br>We recommend adopting an enabling framework to allow consumers to access real-time smart meter data. The objective of the proposed enabling framework should be to ensure access to real-time data for consumers, regardless of their technology choices or when they get a smart meter.<br><br>The enabling framework should:<br>• Include consumer access provision to real-time data.<br>• Expand authorised representatives’ receiving rights to real-time data.<br>• Consider ‘real-time’ as a range to futureproof definitions.<br>• Accommodate new technologies through outcome-focused data-sharing requirements.<br>• Consider interoperability as a matter of performance when sharing real-time data, encouraging participants to adopt standards in the sector.</td><td>F</td><td>Drafting instructions to be determined in any subsequent rule change process.</td></tr>
<tr><td colspan="4">Creating a fit-for-purpose testing and inspection regime for acceleration</td></tr>
<tr><td>20</td><td>Exemptions from the testing and inspection of legacy meters during the acceleration period<br><br>The Commission recommends exempting regular testing and inspection requirements for the legacy meter fleet once the AER approves the legacy meter retirement plan. The time limited exemption would only apply to legacy meters during the acceleration period. The risks are lower given that the remaining legacy meter fleet would be</td><td>G</td><td>15</td></tr>
</table>

| NO | FINAL RECOMMENDATION | APPEN-DIX | DI NO |
|---|---|---|---|
| | retired and replaced as part of the LMRP. | | |
| 21 | **Clarifications to smart meter inspection requirements**<br><br>We recommend obliging MCs to outline their inspection strategy in an AEMO-approved metering asset management strategy (for type 4-6 meters), and requiring AEMO to develop a guideline for inspection outlining the information to be included in such strategies and its approach to approving them. | G | 16, 17, and 18 |

# A ACCELERATING THE DEPLOYMENT OF SMART METERS ACROSS THE NEM

## RECOMMENDATION 1: KEY POINTS

- The Commission recommends accelerating the deployment of smart meters across the NEM — targeting universal deployment by 2030. We consider a five-year acceleration period promotes timely deployment of smart meters, is feasible, and allows retailers to efficiently manage resources. This view is based on extensive engagement with stakeholders and analysis of industry data.
- To achieve this goal, the Commission recommends regulatory arrangements that create a new requirement for DNSPs to progressively retire the legacy meter fleet in the NEM, and for retailers to manage replacement of these retired meters over 2025 to 2030.
- In consultation with key stakeholders, DNSPs would be required to develop 'Legacy meter retirement plans' (LMRPs) that schedule groupings of legacy meters to be retired and replaced each year of the five-year acceleration period. The AER would have a role in reviewing the LMRPs to confirm that DNSPs had undertaken adequate consultation, and properly considered the regulatory objective and guiding principles.
- Retailers would have discretion around how and when they replace the meters each year of the acceleration program. We consider retailers have the incentive to minimise the costs of the smart meter deployment program within these constraints.
- To promote transparency and create regulatory oversight, retailers would be required to report on their annual performance and provide reasons for any divergence from their LMRP schedule to the AER — including explaining how they intend to get back on track if they are not compliant. The Commission recommends that civil penalties would only apply to non-compliance with the final 2030 target.
- The Commission considers new safeguards are required to manage customer risks associated with retailer decisions both on how they pass on meter replacement costs to customers, and to provide notification and information regarding any changes to a customer's retail pricing structure . In our view, these are crucial considerations to support social licence of the smart meter acceleration program.
- Proposed safeguards include prohibiting retailers from charging upfront costs for meter replacements under the acceleration deployment program, and requiring retailers to provide their customers sufficient notice when transitioning them to a different pricing structure, as well as information on how to manage the change. We are not recommending reforms to the network tariff structure statement.

The Commission considers new measures are needed to achieve the timely deployment of smart meters in the NEM to benefit all customers. We recommend reforms to create a regulatory pathway to deliver a universal take up of smart meters by 2030 in NEM jurisdictions.

Our policy recommendations would impact customers in New South Wales, the Australian Capital Territory (ACT), Queensland and South Australia. These jurisdictions are expected to achieve universal penetration by around 2040, if no changes are made to the current framework. Tasmania already has an acceleration program in place with a 2026 target. Victoria has achieved a near-universal take up of smart meters through a DNSP-led deployment strategy over 2009–13. Chapter 7 of the NER does not apply to the Northern Territory (NT) — which has its own regulatory arrangements for metering.

Progress deploying smart meters has been slower and less efficient than expected under the current regulatory framework — due to a lack of industry cooperation and misaligned incentives. Nevertheless, the Commission considers the current industry structure remains appropriate to achieve accelerated deployment of smart meters (appendix A.1).

If implemented, our final recommendations outlined in appendix A.2 will:

- set a clear target in the NER for the accelerated deployment of smart meters between 2025–2030
- establish a standalone regulatory process for the AER to approve a pathway for replacing meters over this acceleration period for each NEM region
- ensure DNSP 'Legacy meter retirement plans' (LMRPs) are based on robust industry consultation — with clear requirements on DNSPs to provide key information to retailers, follow a process set out in the NER, and demonstrate their proposals are consistent with the regulatory objective and principles
- introduce new regulatory obligations on retailers to report their performance and meet interim (year-to-year) targets through to 2030, and a role for the AER to monitor compliance with these interim targets.

We consider new safeguards are needed to support customers through the transition to an energy system that features smart meters. This includes to support customers who are transitioned by their retailer to a different tariff structure, and to protect customers against potential bill impacts caused by upfront retailer charges. These recommended safeguards, outlined in appendix A.3, are new to the final report — reflecting further stakeholder feedback and consideration.

## A.1 Why the Commission is targeting 2030

The Oakley Greenwood study shows that the sooner the goal of universal deployment is achieved, the greater the benefits to consumers (appendix A.1.1).

The large majority of submissions support the acceleration target of a universal deployment of smart meters by 2030.[19] Energy Queensland states this proposal is consistent with the

19 See: ActewAGL (p. 2); AEMO (p. 3); Alinta (p. 3);Aurora Energy (p. 2); CEC (p. 2); ENA (p. 2); Energy Queensland (p. 3); ETU(p. 1); EvoEnergy (p. 2); Intellihub (p. 4); Origin Energy (p. 2); Rheem (p. 1); SA Power Networks (p. 1); Secure Meters (p. 1); SwitchDin (p. 6); TasNetworks (p. 1).

Queensland Government's commitment to target 100 per cent penetration of smart meters by 2030 as set out in the recently published Queensland Energy and Jobs Plan.[20] ACOSS and PIAC recommend bringing the target date for near-universal deployment forward to 2027.[21] Other stakeholders broadly supported the acceleration target to ensure the bulk of the smart meter deployment occurs within a reasonable timeframe.[22]

Some stakeholders suggest that the target date should be dependent on the implementation of the regulatory reforms. Red and Lumo propose an eight-year deadline for the completion of the smart meter rollout from the date the rule change is made.[23] Similarly, Momentum Energy considers the accelerated timeline should be an agreed period of around 7–10 years commencing after the implementation of the regulatory changes and the agreed deployment plan is developed. Momentum Energy states the timeline should not be established until potential issues are resolved.[24]

We have considered the feasibility of achieving universal penetration of smart meters by 2030 (appendix A.1.2), and whether to maintain the current industry structure to achieve accelerated deployment of smart meters (appendix A.1.3) — following further submissions on these topics.

### A.1.1 Cost–benefit analysis demonstrates clear economic benefits for consumers

Cost–benefit analysis undertaken by an independent, expert consultant demonstrates significant economic benefits can be achieved from accelerating the deployment of smart meters to deliver universal take up by 2030. The Oakley Greenwood study shows that acceleration can support a more efficient deployment through increased scale efficiencies and an earlier realisation of benefits associated with smart meters — such as avoided manual meter reading costs.

Overall, Oakley Greenwood found the total benefits of bringing forward meter replacements to 2030 outweigh the total costs. Oakley Greenwood's analysis of the benefits of targeting the year 2032 shows delaying the completion date of accelerated deployment beyond 2030 is likely to lead to a significant reduction in benefits that are not offset by the reduced capital costs. [25]

Momentum Energy states the cost–benefit analysis clearly showed a net positive benefit for consumers.[26] AEC states:[27]

> The Oakley Greenwood cost benefit analysis perhaps represents the most balanced assessment to date, in particular for assessing that if tariff impacts and restoration

20 Energy Queensland submission to draft report, p. 3.

21 PIAC submission to draft report, p. 29; ACOSS submission to draft report, p. 9.

22 See: Energy and Water Ombudsman (NSW, Queensland and SA) (p. 2); Simply Energy (p. 3); Telstra (p. 3); Vector (p. 2).

23 Red and Lumo submission to draft report, p. 2.

24 Momentum Energy submission to draft report, p. 2.

25 The Oakley Greenwood cost–benefit analysis is available at: www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

26 Momentum Energy submission to draft report, p. 1.

27 AEC submission to draft report, p. 1.

> times were removed that the case for accelerated rollout was still positive.

Intellihub notes that the Oakley Greenwood cost–benefit assessment has net benefits even when only a very narrow set of benefits are included, and states it expects that a higher penetration of smart meters will enable a much greater range of services with significantly higher benefits for consumers, retailers and DNSPs.[28] Only a few submissions to the draft report challenged Oakley Greenwood's analysis.[29]

### A.1.2 The 2030 target is ambitious, but feasible

Feedback from stakeholders generally suggests that the metering industry is well-positioned to scale up to deliver the additional deployments required under a 2030 target.

We agree with ETU that the ambition of the target is necessary to drive an ambitious deployment from participants, recruiting more apprentices to meet industry-wide skills needs and unlocking consumer and network benefits sooner.[30] PIAC does not consider a 2030 acceleration target is ambitious enough based on AER data and questions whether it represents a meaningful acceleration of deployment.[31]

On the other hand, EnergyAustralia states it is concerned about a 2030 timeline and says the Commission should seek confirmation from all existing metering coordinators regarding their capacity to efficiently achieve the deployment program by the proposed date.[32] The AER also recommends that the Commission undertake further analysis to ensure the 2030 target date can be (at least largely) achieved.[33]

We have heavily consulted with metering parties through forums, bilateral meetings and the submissions process. Intellihub provides the most comprehensive response to concerns about achieving a 2030 target:[34]

> We are very confident that a target of universal smart meter coverage by 2030 is achievable.
>
> We expect that the main issue we will need to manage to meet the proposed target will be labour supply of meter technicians for undertaking installations. We are comfortable that we can engage and train sufficient installers and scale up the number of installations to meet the targets.
>
> We acknowledge that Australia is currently experiencing labour supply challenges across many parts of the economy and that a large number of installers will be

28 Intellihub submission to draft report, p. 3.

29 In its submission to the draft report, SA Government questions some of Oakley Greenwood's inputs and assumptions (pp. 3–4). Also, AGL questions whether the costs of accelerating the rollout with a regulated 2030 target have been substantiated by Oakley Greenwood (p. 2; 4). We note the costs used by Oakley Greenwood are based on the actual Victorian deployment program costs. See appendix H for further details.

30 ETU submission to draft report, p. 1.

31 PIAC submission to draft report, pp. 9–10.

32 EnergyAustralia submission to draft report, p. 2.

33 AER submission to draft report, p. 3.

34 Intellihub submission to draft report, pp. 3–4.

> required for the accelerated deployment. However, our analysis is that a 100% by 2030 smart meter deployment target would only require the metering industry to engage around 1.5% of current licensed electricians.
>
> We already have extensive field coverage across NSW, the ACT, Queensland, South Australia and Tasmania. Existing electricians can become approved meter installers relatively easily and quickly, only needing to undertake a short training course and onboarding process. Our experience is that we can go from advertising a meter technician role to having the new technician commencing meter installations within 3 months.
>
> Labour supply challenges may be more acute in some parts of the NEM, particularly regional areas, but we consider that these issues are still readily manageable. This view is supported by our current experience in Tasmania. Labour supply for electricians in Tasmania is more challenging that in most other NEM regions, but we have been able to engage and train sufficient installers to be on track to complete a 100% accelerated deployment of smart meters in Tasmania by 2025.
>
> We also note that smart meter deployment rates have started increasing in the last 6 months, meaning that the required ramp up in resources including trained installers has already commenced. Our deployments have nearly doubled in the last 2 years. We expect that annual deployment rates will need to double again to meet the AEMC's proposed targets. We consider that increase to be readily achievable and are already half way there on a percentage basis compared with volumes from 2 years ago.
>
> The supply of smart meter equipment will not be an issue for an accelerated rollout. The Australian market's total demand is estimated to represent less than 1% of annual production of smart meters by suppliers globally. The AEMC's decision not to make material changes to roles and responsibilities also means that agreeing or amending contractual agreements will not be an issue, noting we already have agreements with almost every retailer in the NEM that cover over 99% of customers.

This view is further supported by our analysis of the trend in legacy meter replacements over recent years. Figure A.1 shows the annual rate of meter replacements since 2017, as well as the projected average yearly installation rates under the acceleration program.[35] We expect that the required deployment rates will be achievable by the metering industry.[36]

Figure A.1 shows that the metering industry previously went through a period of rapid capacity expansion after the Competition in metering reforms took effect in December 2017. Based on this past performance and industry consultation, we consider the industry is capable of expanding its capacity in a timely and efficient way to deliver increased deployment for acceleration. The five-year LMRP would provide a lead time and level of

35 Data on actual installs is sourced from AEMO. The illustrative projections for FY-24 and 25 are developed using the average annual growth rate of the number of replacements over the last 5 financial years.

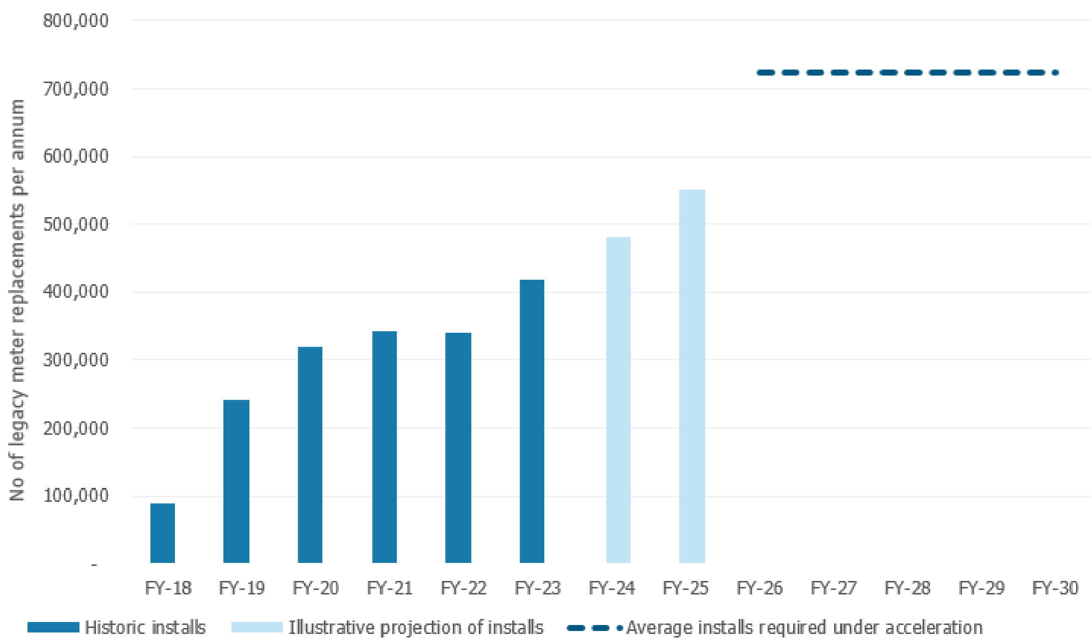
36 If the number of replacements undertaken in FY 24 and 25 are below the illustrative projections, and equal to the number of replacements undertaken in FY 23, then the average number of installs required under acceleration per year would not change significantly. Approximately 762,000 replacements per annum would be required.

certainty, enabling metering businesses to ramp up their workforce and secure adequate meter supplies. The LMRP principles also require work-force impacts to be taken into account in the development of the plan and allow for some ramping up and down of installations across acceleration years.

The data suggests that the annual number of meter replacements is already increasing — reducing the gap between the current rate of deployment and the rate required for acceleration.

Our understanding is the industry has already started to ramp-up installations based on the expectation that the Commission will make a final recommendation in this review to require universal deployment of smart meters by 2030. Data for 2023 to date and broader market intelligence indicate that the trend of increasing meter replacement rates is sustainable. We expect this trend to continue under an acceleration program with clear requirements on DNSPs and retailers to replace legacy meters.

**Figure A.1: The rate of deployment required under acceleration is within reach**




AEMC analysis based on AEMO data

**The 2030 target of universal deployment of smart meters does not mean 100 per cent penetration will be achieved**

The target of universal take up of smart meters across the NEM aims to ensure that every small customer either receives a metering upgrade or has an opportunity to have their meter upgraded by mid-2030.

We recognise universal deployment of smart meters 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. Energy Queensland states:[37]

> … despite participants' best endeavours, there will likely be a percentage of legacy meters that have not been upgraded to a smart meter at the conclusion of the acceleration period. For example, it is expected that there will be a number of legacy meters not replaced as a result of difficulties in gaining access for a meter exchange or where customer site defects have not been remediated.

Unlike Intellihub, Energy Queensland has concerns around labour and meter supplies:[38]

> … there may be unanticipated operational and financial challenges beyond participants' control that will have the potential to impact achievement of the 100 per cent target and substantially increase the costs of compliance, including:
>
> - difficulties in sourcing smart meters due to manufacturer supply constraints and increased demand as a result of accelerated deployment across the NEM; and
> - ongoing issues associated with skills shortages and increased competition for appropriately qualified meter installers.

Similarly, the ETU notes that the acceleration required to achieve this target may be impacted by unavoidable factors like skills shortages, supply shortages, access issues and unremedied site defects.[39]

Customer churn could also delay meter replacements. Origin Energy states:[40]

> For example, if retailer A has been working on a site for say 11 months, before the customer switches to retailer B who only receives 1 month to manage the meter exchange, retailer B is unlikely to be able to complete the roll out in the remaining timeframe and potentially incurs a penalty for failure to do so. There could be a number of such scenarios where the new retailer should not be held accountable due to a reduced timeframe for meter installation.

EnergyAustralia submits that meter exchanges for any reason other than customer initiated are far less likely to be successful on the first attempt and remain unlikely to be completed in subsequent attempts. EnergyAustralia considers the accelerated roll-out will encounter similar percentages of unsuccessful meter installations, and without developing a framework requiring remediation for the range of issues impeding an installation, universal take up of metering is highly unlikely.[41]

37 Energy Queensland submission to draft report, p. 7.
38 ibid, p. 7.
39 ETU submission to draft report, p. 1.
40 Origin Energy submission to draft report, p. 3.
41 EnergyAustralia submission to draft report, p. 3.

The Commission acknowledges remediation costs may be a barrier for some customers. We are not requiring these customers to remediate sites to enable smart meters to be installed. 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 require a customer to undertake remediation of their own installations, and particular groups of customers may not be in a position to readily remediate — such as tenants, customers in social housing and customers with lower incomes[42]

Notwithstanding the measures proposed by us to encourage customers to undertake remediation of site defects and the potential for government support (see appendix D.3), it is expected that the above barriers will persist for at least a small proportion of customer sites. This has been the experience in other jurisdictions.

Overall, we expect approximately 10–15 per cent of sites will be higher cost or difficult to install smart meters at due to meter board remediation, site access and customer refusal issues. This estimate is based on evidence provided in submissions[43] and industry discussions. Government initiatives to support site remediation could significantly reduce these barriers to installation (see appendix D.3).

### A.1.3 Why the Commission recommends maintaining the current industry structure

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

Some stakeholder submissions recommend changes to return the responsibilities for metering to DNSPs — including allowing DNSPs to appoint the metering coordinator.[44] Stakeholders state that this change could improve the efficiency of the deployment program, reduce costs, eliminate split incentives and simplify acceleration.

The Commission considers the proposed change would create new problems, the offsetting benefits would not be material, and our recommendations address the issues raised by stakeholders. 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. Although there are issues with the current framework, we consider the current industry structure is more likely to deliver the benefits envisaged under the 2015 *Competition in metering* rule change, and promotes innovation in technology and services to customers.

These issues are discussed in more detail in appendix B.

42 This applies where remediation is required only to facilitate smart meter installations. Unsafe customer installations may need to be disconnected pending repair by the owner.

43 See: EnergyAustralia submission to draft report, p. 3; Vector submission to directions paper, p. 17.

44 See: ACOSS (p. 3); PIAC (p. 3); Powermetric (p. 2); SA Power Networks (p. 4).

## A.2 New regulatory arrangements to deliver smart meters for customers

The Commission recommends regulatory arrangements that create a new requirement for DNSPs to progressively retire the legacy meter fleet in the NEM, and for retailers to manage replacement of these retired meters (appendix A.2.1). This is Option 1 from the draft report, the LMRP approach, which was supported by a large majority of submissions.[45]

Under the Commission's proposal, DNSPs would be required to develop the schedule of meters to be retired over 2025–30 and submit draft LMRPs to the AER by late 2024 to early 2025. This process would involve DNSPs providing key information to and undertaking consultation with retailers, metering parties and other stakeholders to consider a pathway for retiring legacy (type 5 and 6) meters for each jurisdiction (appendix A.2.2). The DNSPs would be required to demonstrate their proposals meet the LMRP objective and guiding principles (appendix A.2.3).

The AER would have a role in reviewing the LMRPs developed by DNSPs. The AER would approve a LMRP if it is satisfied that the DNSP had undertaken adequate consultation, and properly considered the regulatory objective and guiding principles. The AER would have until 31 March 2025 to undertake its approval process. This new regulatory process would have resource implications for the AER.

To create incentives for retailers and metering coordinators to meet interim targets and the final goal of universal deployment of smart meters by 2030, we consider the AER should be required to undertake additional performance reporting, compliance and enforcement functions (appendix A.2.4).

### A.2.1 The Legacy meter retirement plan is the key mechanism to accelerate the deployment of smart meters in the NEM

The Commission recommends that each DNSP be required to develop, and have approved by the AER, a LMRP — which provides an annual schedule of meters (such as by postcode) to be retired each year in order to meet the 2030 target of universal take up.

In forming these recommendations, we have sought to:

- create certainty and strong requirements on industry to accelerate the take up of smart meters
- minimise the regulatory burden of this process on the AER and industry
- provide sufficient flexibility for different approaches to be adopted in each network area — balancing, for example, the achievement of geographical economies and the management of workforce constraints.

DNSPs, retailers, metering coordinators and the AER have key roles to play for the successful implementation of this regulatory framework.

45 See: ActewAGL (p. 2); AER (p. 3); Alinta (p. 3); CEC (p. 2); ENA (p. 2); Energy Australia (p. 1); Energy Queensland (pp. 10–11); EvoEnergy (p. 2); EWO (p. 3); Green metering (p. 2); Intellihub (p. 5); Momentum Energy (p. 4); Origin Energy (p. 1); Powermetric (p. 2); Red and Lumo (p. 2); SA Power Networks (p. 1); Simply Energy (p. 2); SwitchDin (p. 7); TasNetworks (p. 1).

### Initiating the acceleration program

Requiring DNSPs to retire existing type 5 and 6 meters in the NEM according to the LMRP schedules, and retailers to replace those meters within 12 months of retirement, provides a clear mechanism to accelerate deployment of smart meters.

A LMRP approach is most practical, given there are fewer DNSPs than retailers, and DNSPs have detailed information on the existing legacy meter fleet (whereas retailers may not). The regulatory process outlined in section A.2.2 to develop the LMRPs allows all relevant and affected parties to have input into and visibility of the plan — promoting openness and transparency. Momentum Energy states:[46]

> As the current stock of legacy meters are owned by the DNSPs they hold relevant information regarding the location, condition and life expectancy of these meters and therefore they are a fundamental party to developing the legacy meter replacement plan.

The forward schedule of legacy meters to be retired enables retailers and metering parties to undertake and coordinate planning, manage risks and prioritise their efforts to minimise costs for customers. The expectation is for the sector to work together in each jurisdiction to develop LMRPs that best promote the long term interests of consumers. For example, meters in 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. Intellihub highlights that a collaborative approach to developing these plans will best utilise the strengths and information held by each of the relevant parties to help maximise the benefits and minimise costs.[47]

This acceleration mechanism will be in addition to the existing types of deployments available under the rules. Although retailers can continue with their current strategies, the retailer-led deployment model would no longer be the underlying framework. During the LMRP new meter deployments[48] would be treated in the same way as meters retired under the LMRP, meaning that retailers and metering parties would have the option to replace meters ahead of the LMRP schedules under the acceleration program.[49] A smart meter must still be installed for new connections and replacements. Consumers can evaluate the benefits of alternative energy service offerings and request a smart meter themselves.

### Other options considered by the Commission

46 Momentum Energy submission to draft report, p. 3.

47 Intellihub submission to draft report, p. 5.

48 As defined in the NERR, rule 3.

49 In its submission to the draft report, Vector recommends that a credit system be devised where meters installed in 2023 and 2024 be counted towards retailers' targets for the first two years of the accelerated rollout (p. 7). We consider it is open for retailers to drive installations sooner, which will help to meet their future interim targets. The purpose of the LMRP is to develop a deliberate, coordinated strategy to promote the more efficient deployment of smart meters, which is achievable for retailers and metering coordinators over a five-year period.

The draft report outlined the option of prescribing the LMRPs in the rules or AER guidelines, rather than relying on the LMRP process (Option 2). Telstra considers Option 2 is more feasible and appropriate, submitting:[50]

> A DNSP driven Plan, as contemplated by Option 1, is anachronistic in the context of meter contestability. DNSPs play a legacy role in metering, and an acceleration of smart meter uptake needn't be hampered or delayed by DNSPs developing Plans — given that they won't be involved in the deployment or reading of the new smart meters.

In our view, DNSPs are practically best placed to develop a clear pathway for replacing legacy meters over the five-year period. DNSPs have the best information on the status and location of legacy meters, and will provide insights into the areas of their networks where customers would benefit from an earlier deployment of smart meters. For example, DNSPs can identify the need to replace ageing distribution load control equipment, target areas with greater safety or reliability risks, and more efficient changes to manual meter reading routes.[51]

Another option to accelerate deployment of smart meters that we considered is retailer targets (Option 3 in the draft report). Secure Meters prefers this option as it keeps the responsibility as per the current market roles and structure — noting some aspects of Option1 could be included, and DNSPs would need to identify difficult sites and have an active participation in solutions.[52]Vector also prefers Option 3:[53]

> While Option 1 is feasible, it has issues that appear complex and difficult to resolve. For example, how can a geographical rollout prepared by the DNSP avoid localised boom and bust scenarios (by adequately considering available resources) when DNSPs are not aware of the MP's resourcing levels. Option 1 will also require changes to market B2B transactions and MSATS, which would be a 'sunk cost' once the rollout is completed.
>
> In contrast, Option 3 is simpler, avoids the material issues associated with Option 1, and can be implemented and monitored without the need for new industry B2B infrastructure. A shortcoming of Option 3 is that DNSPs will incur higher costs as reading routes are not retired systematically. However, given the expected level of failed exchange attempts (Unable To Complete) that result in the legacy meter remaining for some time after the adjacent meters have been exchanged, it is our view that none of the options in the Draft Report will protect DNSPs from this issue.

The Commission considers that there are several disadvantages of Option 3. For example, the role for DNSPs is unclear, there is no mechanism for retailers to coordinate their plans,

50 Telstra submission to draft report, p. 4.
51 Intellihub submission to draft report, p. 5.
52 Secure Meters submission to draft report, p. 5
53 Vector submission to draft report, pp. 6–7.

benefits to DNSP of prioritising, for example, LV network visibility to support network operations (including export hosting services) may not be considered,[54] and DNSPs and other parties would not have clear visibility of the plans. Further, retailers may have incentives to delay meter replacements to minimise the risk of customer churn and target what they consider to be higher value customers — leaving the difficult metering sites until last, and potentially creating equity concerns if a specific cohort of customers is deprioritised.

**Roles and responsibilities under the Legacy meter retirement plan approach**

The Commission recommends a fit-for-purpose regulatory process, outlined in appendix A.2.2, which requires the AER to approve the LMRPs proposed by the DNSPs. The AER's assessment would be 'light-touch' and focus on whether the DNSPs have met their requirements in developing the proposals — including demonstrating they have considered the LMRP objective and guiding principles (see appendix A.2.3). The AER would also be responsible for performance reporting, compliance and enforcement. This would have resource implications for the AER. For example, additional full time equivalent staff may be required to approve the DNSP LMRP proposals (including potentially revised LMRPs), and undertake ongoing compliance and enforcement functions. Further resources may also be required to undertake additional performance reporting, consider implications for the 'default market offer', and assess any ring-fencing applications (see appendix B).

The role of DNSPs is to facilitate input from relevant industry participants into the development of the LMRPs to sequence groupings of NMIs to be replaced over the five-year period for each of their network areas (such as by postcode). DNSPs would be responsible for consulting on, developing and submitting the LMRP proposals to the AER. The LMRP minimum content requirements are set out below.

Retailers and metering coordinators would remain responsible for metering services for small customers.[55] Retailers would implement the LMRP for each network area — including detailed planning, and managing and resourcing the deployment of smart meters over the five-year period. AEMO states retailers and their appointed metering coordinators are best placed to coordinate resources to obtain the most efficient and effective rollout, if an incentive arrangement is sufficiently well-established.[56]

Retailers would be required to follow the LMRP schedules and replace the retired meters in a timely way — meeting interim targets over 2025 to 2030. Retailers would also be required to report annually on their performance as part of their regular reporting to the AER under the NERR (see appendix A.2.4).

**What's included in the Legacy meter retirement plan**

---

54 In its submission to the draft report, SA Power Networks identifies other specific opportunities to accelerate customer benefits by staging and prioritising replacements, including: coordinating the replacement of meters at multi-occupancy premises; prioritising cohorts such as customers at higher risk of a degraded neutral connection to their premises, to maximise safety benefits (as smart meter data can detect faults to the customer's neutral connection that present an electric shock hazard in the home); and prioritising segments such as customers with traditional off-peak controlled load hot water, to facilitate shifting of these loads to the daytime 'solar sponge' period in high-solar jurisdictions like South Australia, saving customers money. (p. 7)

55 Under NER cl. 7.2.1, the retailer (financially responsible market participant) must ensure that a metering coordinator is appointed in respect of the connection point. The role and responsibility of metering coordinators is set out in NER cl. 7.3.

56 AEMO submission to draft report, p. 1.

The Commission considers that it is appropriate for the NER to set out the minimum content requirements for the LMRPs.

A LMRP would provide an annual schedule of meters (NMIs) to be retired in each year from 1 July 2025 to 30 June 2030. This is a relatively detailed plan for the order in which all existing type 5 and type 6 meters will be retired — triggering replacement with type 4 meters by retailers and metering coordinators by 30 June 2030 to give effect to the LMRP objective and principles. Legacy meters are expected to be retired by geographic groupings — for example, by postcode, zone substation or meter reading route.

The DNSP would begin retiring legacy meters according to the schedule — starting 1 July 2025 for NMIs to be replaced by retailers within 12-months to 30 June 2026, then 1 July 2026, 1 July 2027, 1 July 2028 and 1 July 2029 — which make up the annual interim targets (discussed below).[57]

The DNSPs' LMRPs should set out how the above information will be provided to retailers in a consistent, standardised and accessible format — preferably across all DNSPs.

The AER would be required to publish the approved LMRPs to promote transparency — except for any confidential information.[58]

**Why interim targets**

The Commission's position is that regular interim milestones are preferable to a single target of universal deployment by 2030 for the following reasons:

- Interim targets provide greater certainty that the acceleration target will be achieved, and help retailers and metering parties to undertake and coordinate planning.
- Reasonably consistent year-to-year deployment of smart meters from 1 July 2025 to 30 June 2030 supports earlier realisation of the benefits.
- Interim targets enable intervention in a timely manner, if necessary.

Several stakeholder submissions support interim targets. Energy Queensland considers a 12-month timeframe to replace retired meters should be sufficient to allow participants to prioritise and plan their workloads under normal circumstances.[59] SA Power Networks submits it should not be longer than 12 months and would ideally be shorter.[60] SA Government states having interim timeframes and compliance checks is more likely to enable successful acceleration in smart meter deployment — providing greater certainty that the meter replacement rate increase and ensures some acceleration occurs from the outset.[61]

57 In its submission to draft report, Intellihub states that prescribing interim targets in the NER is not necessary (p. 4).

58 We recognise some aspects of the LMRPs may contain confidential information. The AER's 2017 confidentiality guideline sets out how DNSPs must make confidentiality claims over information they submit to the AER, and sets out a scheme for how the AER will handle confidentiality claims. See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/confidentiality-guideline-2017

59 Energy Queensland submission to draft report, p. 12.

60 SA Power Networks submission to draft report, p. 6.

61 SA Government submission to draft report, p. 4.

Stakeholders generally agree a LMRP 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.[62] Origin Energy states the application of interim targets not only ensures a measured approach toward the target date but provides guidance for metering providers to assist in resourcing and maintaining their workforce.[63] Moreover, Vector submits metering providers require clear visibility of the rollout profile to ensure that resources will be available to meet demand.[64]

As discussed below, we propose for retailers to undertake best endeavours to meet the interim targets. The AER would monitor and report on retailers' annual performance.

### A.2.2 Regulatory process to establish the Legacy meter retirement plans

We consider the establishment of the LMRPs should be undertaken as part of a one-off, standalone process.

The regulatory process outlined below provides a 'light-touch' approach for the AER to approve the LMRPs. DNSPs would be required to manage consultation on the LMRPs. DNSPs are well-placed to weigh retailer and other stakeholder feedback to form a coherent and achievable approach that minimises installation costs through geographical deployment economies, while considering workforce and supply constraints. Retailers and metering parties will need some time and certainty to begin the process of ramping up and scheduling works. The AER would then be responsible for the ongoing oversight of the implementation of the acceleration program.

The Commission acknowledges this new requirement would have resource implications for DNSPs. We do not consider special consideration is required under the regulatory framework to ensure DNSPs have a reasonable opportunity to recover their efficient costs of developing the LMRPs.

Retailers would have the ability to seek amendments to their relevant LMRP schedules, if a LMRP is affected by a material error, change in circumstances or 'event'. For example, a revision may be required when an event occurs that was not accounted for, or that is beyond the reasonable control of the DNSP or retailer, that may negatively impact the retailer's ability to meet the LMRP schedule and associated interim targets.

#### Summary of steps in the LMRP process

We recommend a process for the development and approval of DNSP LMRPs to include the following steps (as also shown in Figure A.2):

1. **Development of the Legacy meter retirement plans |** DNSPs would be responsible for developing the LMRPs. The DNSP would provide the retailers with detailed information about the sites at which legacy meters need to be replaced to the extent that this information is available. DNSPs must then consult with retailers and other affected stakeholders on the draft LMRPs and address their feedback. LMRP proposals submitted

62 See: ACOSS (p. 10); EDMI (p. 3); EWO (p. 2); PIAC (p. 12); PLUS ES (p. 10).

63 Origin Energy submission to draft report, p. 2.

64 Vector submission to draft report, p. 3.

to the AER must be made in accordance with the objective, guiding principles and content requirements.

2. **AER check |** The AER must ensure that the DNSPs have followed the required process and that LMRPs include the specified details about the customer sites. If compliant, the AER would approve and publish the LMRPs on its website. The DNSPs would be required to have their proposals approved by the AER no later than 31 March 2025. The Commission's view is that a limited review is required by the AER of the LMRPs to confirm compliance with the relevant NER requirements. The AER would not be required to assess the merits of each DNSP's LMRP.
3. **Implementation |** The retailers would be required to follow their LMRP schedule/s and replace the retired legacy meters in a timely way — meeting the interim and final targets over 2025–30. Retailers would be required to report annually on their performance as part of the AER's retail markets report under the NERR.
4. **Revision process |** We propose to provide a process that allows, in certain circumstances, for a retailer to apply for amendments to be made to the schedule of meters it is required to replace over the acceleration period. This would ensure the LMRP continues to provide a clear and robust plan for industry to work together to progress over the acceleration period. Retailers can apply to the relevant DNSP to amend their LMRP. The DNSP may revise the LMRP if a materiality threshold has been met. If so, the DNSP would need to undertake consultation and ensure the amended LMRP is consistent with the LMRP objective and principles. The AER would then be required to check the amended LMRP is compliant, similar to the initial approval process (see step 2).

**Figure A.2: Recommended Legacy meter retirement plan regulatory process**


AEMC

### DNSPs would be largely responsible for setting the pathway

It is expected that the development of the LMRPs will be challenging given the number of retailers involved. We anticipate retailers and other stakeholders will have different and sometimes conflicting objectives. For example, some retailers may wish to prioritise difficult-to-access customers to take advantage of the remote capabilities of smart meters to reduce the number of estimated bills, while others may prefer targeting customers based on specific usage profiles to introduce new products. Consultation may involve 30 or more retailers in some regions.

PIAC submits the proposal for DNSPs to be the 'centre of planning' has merit and is the only option presented that is feasible, and states DNSPs will need to have the authority to make decisions where consensus cannot be reached on any aspect of the plan. PIAC considers

DNSPs will not be practically able to reach meaningful agreement with retailers and metering parties.[65]

Similarly, SA Power Networks states:[66]

> Stakeholders will have competing objectives and priorities and so no plan will fully satisfy all parties. It will be important, therefore, that the framework gives clear authority to the DNSP to weigh competing priorities and make decisions in cases where stakeholders disagree. So long as the DNSP demonstrates that it has engaged adequately and transparently with all stakeholders in the development of the plan and, where stakeholders disagree, appropriately applied the agreed principles in making decisions that best promote the NEO, the plan should be capable of acceptance by the AER.

The Commission considers it would be appropriate for DNSPs to apply their judgement balancing retailer and other stakeholder views to determine a deployment program pathway that is practical and broadly promotes the long term interests of consumers — consistent with the LMRP objective and principles (see appendix A.2.3).

There are several factors that would need to be considered by DNSPs, as highlighted by ENA and other stakeholders.[67] We propose consultation requirements to ensure DNSPs consider how to broadly achieve geographical efficiencies while accounting for resourcing issues.

There may be scope to undertake very detailed planning to optimise the profile of replacements to maximise efficiencies to an extent. However, DNSPs would not be required to undertake this type of analysis in developing the LMRPs (nor the AER in approving the LMRPs). Our view is the order in which meters are installed over 2025–30 would not materially affect the overall benefits achieved by the acceleration program, as discussed further below.

### DNSPs would be required to undertake robust consultation

Some stakeholders said that the LMRPs should give strong weight to retailers' and metering parties' input (as further discussed below). Other stakeholders, such as consumers and governments, may provide valuable input too. Intellihub highlights consumer representatives may have useful insights related to the speed of the deployment program and which types of consumers or geographic areas should be targeted first.[68] These stakeholders are not expected to necessarily engage on the detail of the LMRP schedules, but would be well-placed to consider whether the proposals are consistent with the LMRP objective and principles.

The Commission recommends that after a DNSP has developed a draft LMRP, and before submitting it to the AER for approval, the DNSP would be required to:

65 PIAC submission to draft report, p. 11.

66 SA Power Networks submission to draft report, pp. 5–6.

67 For example, see: ENA (p. 2); EWO (p. 2); Intellihub (p. 5); SA Power Networks (p. 7); Telstra (p. 4).

68 Intellihub submission to draft report, p. 5.

- provide relevant retailers with information about the sites at which a legacy meter would need to be replaced
- consult with the retailers and other relevant and affected parties
- provide the relevant parties with a minimum period of time to review the draft LMRP and provide comments
- address any comments or submissions received from the relevant parties before submitting the LMRP to the AER for approval.

DNSPs would need to provide available information to enable retailers and metering coordinators to both provide input into the development of the LMRPs, and undertake more detailed planning and scheduling of metering works to meet the interim targets. This would include full and detailed information about the sites at which a legacy meter would need to be replaced for retailers to be able to use the plan, as suggested by Red and Lumo.[69]

As part of this consultation, we propose a requirement on DNSPs to undertake 'best endeavours' to provide the following information where known: the NMI and its location, meter age, the type and make of the meter, building type (residential or business), a description of issues that may hinder safe access (eg, the presence of menacing animals and industry locks) and the likely configuration of the meter board, and a high-level assessment to identify shared fusing or site remediation issues (eg, the presence of asbestos).

To strengthen the consultation requirements, as part of the LMRP proposals, we consider DNSPs should be required to submit a report to the AER:

- explaining how the proposals are consistent with the LMRP objective and principles (see appendix A.2.3)
- describing how the DNSP has engaged with retailers, metering parties and other relevant and affected stakeholders in developing the proposal, the relevant concerns identified as a result of that engagement, and how the DNSP has sought to address those concerns.

If a LMRP does not comply with the relevant requirements, the AER may notify the DNSP that the LMRP requires resubmission. The notice must be given as soon as practicable and must state why, and in what respects, the AER considers the LMRP to be non-compliant. A DNSP must, within 15 business days after receiving the notice, resubmit its LMRP in an amended form that complies with the relevant requirements set out in the notice. The AER may extend the timeframe for resubmission if it considers this necessary and appropriate in the circumstances.[70]

**The sequencing of the rollout is not as important as timely completion**

Several retailers raised concerns in submissions to the draft report about ensuring DNSPs give appropriate weight to the views of affected parties.[71] Momentum Energy states a requirement for DNSPs to consult with stakeholders is not sufficient to ensure retailer views

69 Red and Lumo submission to draft report, p. 3.

70 For example, if the AER considers that the LMRP is non-compliant because there has been insufficient consultation with the relevant parties, then the AER may agree to extend the 15 business day period to allow the DNSP time to properly consult on the LMRP prior to resubmission.

71 For example, see: Alinta (p. 4); EnergyAustalia (p. 2); Momentum Energy (p. 3); Origin Energy (pp. 2–3); Red and Lumo (p. 3).

will be effectively considered and/or actioned.[72] Momentum Energy proposes that an independent expert be appointed to work within each DNSP to ensure a fair and transparent approach to the development of the LMRP.[73] The AER's suggests a process where DNSPs are required to submit an independent third-party review of the plan.[74]

The success of LMRPs will rely to an extent on DNSPs cooperation and coordination with retailers and metering providers, as the AER submits.[75] However, we disagree with Alinta that the AER will need to play an active role in assessing (the merits of) LMRPs, and ensuring that DNSPs develop and update them based on input from retailers and metering coordinators.[76] As part of its compliance role, the AER is expected to monitor the implementation of the acceleration program and can identify issues — providing effective oversight. This does not go as far as SA Power Networks' proposal to establish a governance framework to hold each party accountable for performance against the agreed plan.[77]

In considering the appropriate role of the AER in development of the LMRPs, the Commission has carefully weighed up the likely costs and benefits of greater regulatory oversight (beyond the compliance check process). On balance, the Commission considers that the costs of greater AER involvement to facilitate development of the LMRPs and potentially foster industry agreement would outweigh any potential benefits to consumers. Geographical efficiencies can be largely realised by targeting contiguous areas (such as suburbs) within interim periods over the five-year acceleration program. This would not require a detailed AER assessment to ensure DNSPs have properly weighed the range of efficiency benefits so that LMRP schedules are based on an optimal deployment strategy (as noted above). Therefore, significant AER consideration of the merits of each LMRP and a consultation process seeking stakeholder submissions on the DNSP proposals is not required.

**The need for a timely regulatory process**

The Commission proposes for the AER approval process of LMRPs to be completed by 31 March 2025 for DNSPs in New South Wales, the ACT, Queensland and South Australia.[78] This would allow retailers and metering parties to ramp up operations to formally begin the acceleration program from 1 July 2025.

To provide the AER sufficient time to undertake its assessment and meet this deadline, the New South Wales, ACT, Queensland and South Australia DNSPs would need to submit their LMRP proposals to the AER by late 2024 to early 2025. So, these DNSPs would need to begin developing their LMRP proposals by mid- to late 2024.

72 Momentum Energy submission to draft report, p. 3.

73 ibid, p. 3.

74 AER submission to draft report, p. 5.

75 ibid, p. 4.

76 Alinta submission to draft report, p. 5.

77 SA Power Networks submission to draft report, p. 2; 6.

78 We agree with TasNetworks' submission (p. 2) that it should not be required to be included in this regulatory process, given its smart meter deployment program is expected to be completed by 2026.

There is little scope for delays to a rule changes process, as highlighted by Intellihub.[79] The Commission requires a proponent to submit the rule change to us — we cannot initiative the process ourselves. We are committed to prioritising this reform program. We consider our final recommendations are robust and reflect the very significant input and feedback we have received from a broad group of stakeholders.

As discussed below, we do not propose for the AER to provide further guidance on implementation of the regulatory process. Further, we acknowledge the acceleration program would have some implications for the AER's network revenue determination processes.

**AER guidelines would delay the acceleration program**

Some stakeholders have called for the AER to develop guidelines to help efficiently manage the regulatory process. The AER submits a framework could be explored where broad obligations on networks are set out in the NER, and the AER creates a guideline setting out what we consider would meet the criteria of enabling efficient replacement.[80] Alinta considers the AER should develop enforceable guidelines in consultation with industry to ensure consistency across different networks and jurisdictions.[81] Green Metering recommends an escalation and resolution guideline to ensure there is a path for resolution where issues may arise.[82]

Although we consider there may be a case for the AER to provide guidance on its expectations for how DNSPs develop their LMRP proposals, and how the AER will assess the proposals to an extent, further consultation and development of these guidelines would consume stakeholder and AER resources, and create a significant risk of delays to the acceleration program for limited material benefit. Given the level of ongoing consultation as part of this review, we recommend that guidance on the content, objective and principles to be reflected in LMRPs be provided in the NER itself, rather than AER guidelines — incorporating stakeholders' extensive feedback throughout this review.

**Interrelationships with AER distribution revenue determination process**

DNSPs and the AER would need to factor in the accelerated deployment of smart meters as part of the revenue determinations. The AER submits there will be a range of interactions with costs within the regulatory proposals and network pricing.[83] For example, it is expected that the DNSPs will reflect a higher take up of smart meters in their CER integration strategies — given smart meters will enhance their capabilities to manage increasing CER exports.

Also, DNSPs and the AER generally apply price caps for individual metering services as part of the alternative control services component. A 'base–step–trend' forecasting approach is typically used to estimate efficient operating expenditure for metering services, including adjustments to reflect metering churn as customers install smart meters. The more

79 Intellihub submission to draft report, p. 5.
80 AER submission to draft report, p. 5.
81 Alinta submission to draft report, p. 4.
82 Green Metering submission to draft report, p. 3.
83 AER submission to draft report, p. 5.

customers with smart meters, the less DNSP operating expenditure required for routine and special meter reads. These forecasts of meter churn should reflect progression towards the goal of universal deployment of smart meters by mid-2030.

The AER has several regulatory mechanisms to manage the uncertainty of a rule change, to accelerate the deployment of smart meters, for the New South Wales and ACT DNSP revenue determination processes due to be finalised in April 2023 — given a Commission rule change decision would not occur until at least mid- to late 2024.

**Cost recovery by DNSPs to manage the LMRP process**

DNSPs are expected to incur costs to manage the LMRP process. The Commission is seeking to minimise the regulatory complexity and upfront costs of the process to develop the LMRPs to the extent possible. However, DNSPs are expected to undertake new activities and there is a question of how they would be able to recover these costs under the regulatory framework.

The LMRP process would occur following the current New South Wales and the ACT distribution network revenue determination processes, and before the start of the South Australia and Queensland DNSPs next regulatory period. These DNSPs would be required to incur new costs in undertaking consultation to develop the LMRPs under the standalone process, engage in the AER's regulatory process and for ongoing administration of the LMRPs. ENA states:[84]

> DNSPs will incur additional unfunded costs to develop the plan, along with likely costs to administer the plan during its life. These costs, however, are unlikely to meet the materiality thresholds for cost pass through events in the National Electricity Rules (NER) and therefore specific cost recovery provisions would need to be included in any rule change that also places the legacy meter retirement plan obligation on DNSPs.

SA Power Networks submits any rule change would need to include clear provisions for the DNSP to recover its efficient costs to perform the planning and coordination functions, independent of the timing of their regulatory determination cycles.[85] Further, SA Power Networks says:[86]

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

84 ENA submission to draft report, pp. 2–3.

85 SA Power Networks submission to draft report, p. 2.

86 ibid, p. 6.

accelerated meter rollout.

The Commission considers the general cost pass through provisions of the regulatory framework should apply. The NER already explicitly accommodates cost pass through for regulatory change events within revenue determination periods.[87] It would be open to DNSPs to propose a cost pass through for costs incurred in consulting on and developing the LMRPs, and navigate the AER approval process, if the costs meet the current materiality threshold.[88]

The Commission does not propose to waive the materiality threshold for cost pass through applications associated with the LMRP process requirements, as suggested by SA Power Networks above. Industry consultation and progressing the deployment of smart meter infrastructure is well within the business-as-usual activities of DNSPs and serves their future operations and CER integration strategies. The Commission similarly would not seek to waive the materiality threshold for negative cost events — promoting symmetrical outcomes for DNSPs. We are not persuaded that this regulatory change event has sufficient unique features that are not present in other regulatory change events, or that overriding the existing arrangements would be in the long term interests of consumers.

'Cost pass throughs' are an important mechanism under the NER to support the incentive framework. A cost pass through may occur within a regulatory control period when a pre-defined exogenous event occurs which materially increases or decreases a DNSP's costs. In these circumstances, the AER may approve a positive (or negative) pass through amount under the cost pass through provisions in the NER. Cost pass throughs are needed because of the inability of DNSPs to forecast all possible events that could affect their ability to recover efficient costs.

However, the incentive properties of cost pass throughs are very weak and undermine the underlying intent of the ex ante regulatory framework to promote strong efficiency incentives. Therefore, the regulatory framework provides that cost pass throughs — for both positive and negative pass through events — should apply to the individual circumstances of each DNSP and include relatively high thresholds to trigger a cost pass through event.

**Retailers would have the flexibility to seek revisions to their Legacy meter retirement plan schedules, if there is a significant change in circumstances**

The Commission considers there should be an ability for retailers to adjust the year-to-year installation targets under the LMRP schedule in some limited circumstances. We recognise a five-year plan would need to make certain assumptions. It is possible there could be a significant change of circumstances not foreseen under the LMRP that may negatively impact retailers' ability to comply with their requirements — such as unforeseeable field resource or meter equipment supply constraints, natural disasters or weather events, as identified by Red and Lumo.[89]

87 NER cl. 6.6.1.

88 Under chapter 10 of the NER, the materiality threshold for the purposes of a cost pass through application is 1 per cent of a DNSP's annual revenue requirement (for costs incurred for that regulatory year).

89 Red and Lumo submission to draft report, p. 2.

We consider this flexibility should be provided on an 'as needed' basis, rather than establishing a process of annual revisions of the LMRPs (as suggested by Momentum Energy[90] and Origin[91]), or a mid-point review (as proposed by the AER[92]) Repeated regulatory review processes would create significant administrative costs and may require new rounds of stakeholder consultation.

The Commission proposes to create a process that would allow for a retailer to apply for amendments to be made to the schedule of meters that are retired over the acceleration period. The retailer would be required to put forward an amended version of the LMRP for the relevant DNSP's consideration.

We consider a materiality threshold should apply. The DNSP may agree to amend an LMRP, if it appears to the DNSP that the plan is affected by a material error, material change of circumstances or 'event'. When a retailer seeks an amendment to account for a material change in circumstances or event, the retailer's application to the DNSP should demonstrate:

- an *event* that is beyond the reasonable control of the DNSP and/or retailer has occurred, and the occurrence of that event could not reasonably have been foreseen by the DNSP and/or retailer at the time of the development of the LMRP
- a failure to adjust the LMRP schedule to reflect the consequences of the event would be likely to materially adversely affect the ability of the relevant retailer to comply with its obligations to meet the interim targets.

When one or both of the materiality thresholds are met, the DNSP may amend the LMRP, and if it chooses to do so, may either accept the amendments proposed by the retailer or may propose its own amendments to address the material error or material change in circumstances or event. In either case, the DNSP must undertake consultation regarding any proposed amendments, and ensure the proposed amendments are consistent with the LMRP objective and principles described above. Following such consultation, the amended LMRP would be required to be approved by the AER (consistent with the approach for new LMRPs).

The AER would be required to make its decision on whether to approve the amended LMRP within 20 business days. If approved, the AER must then re-publish the LMRP and notify relevant stakeholders.

### A.2.3 Guiding principles set the pathway for retiring legacy meters

The Commission considers the NER should include a clear objective and set of principles to guide the DNSPs' development of the LMRPs.

Consistent with the National Electricity Objective, the proposed LMRP objective is:[93]

90 Momentum Energy submission to draft report, p. 3.

91 Origin Energy submission to draft report, p. 1.

92 AER submission to draft report, p. 6.

93 In its submission to the draft report, Intellihub proposes a principle that makes it clear 2030 is the latest date that plans must target universal deployment by, and the plans could target completion of the deployment by an earlier date if supported by stakeholders (p. 6). In their submissions to the draft report, EWO (pp. 2–3) and PIAC (p. 11) propose for the principles to include an equity consideration. We consider it is more appropriate to include 'fairness' as part of the LMRP objective.

To require retailers and metering coordinators to replace all existing type 5 and type 6 meters with a type 4 meter by 30 June 2030 in a timely, cost effective, fair and safe way.

The proposed LMRP principles below are designed to provide DNSPs and affected parties with flexibility to develop the LMRPs in a manner that will contribute to the LMRP objective based on jurisdictional circumstances, while providing certainty for retailers especially on what factors the DNSPs must take into account.

**Legacy meter retirement plan principles**

The Commission recommends the order of retirement of legacy meter NMIs and their allocation to annual interim targets must take into account:

1. The annual interim targets for each financial year, which must be between approximately 15–25 per cent of the total number of meters to be replaced under the LMRP.
2. The overall efficiency of the acceleration program over the five-year period of the LMRP, including costs and cost savings for all relevant market participants. For example, in the interests of efficiency, legacy meters may be retired in geographic groupings — such as by postcode, zone substation or meter reading route.
3. The impacts on retailers and other related and affected parties. In particular, the ramping up and down of the deployment program must account for workforce planning and availability considerations for meter providers across the five-year period of the LMRP — including enabling efficient workforce planning for meter deployments in regional areas.

The LMRP objective and above guiding principles are supported by the minimum content and process requirements outlined above — which have been strengthened in this final report. For example, there is an obligation on DNSPs to consult with retailers, metering coordinators, governments and consumer groups when preparing their proposed LMRPs. The AER would be required to examine whether the DNSPs have reasonably considered this stakeholder input, as well as the objective and principles.[94]

Submissions largely endorsed the proposed principles outlined in the draft report.[95] Notwithstanding this support, the Commission has made several drafting changes to the principles. These changes are based on further consultation with retailers, metering coordinators, DNSPs and some other key stakeholders.

First, a principle requiring DNSPs to develop the LMRPs with input from key stakeholders is made redundant by the strengthened process requirements. Similarly, a requirement on DNSPs to provide available information to enable retailers and metering parties to undertake

94 In its submission to the draft report, the AER suggests the principles should be clear about what hierarchy of criteria it should take into account (p. 4). Also, Alinta submits the principles should include how disagreements over the plan's features or implementation can be resolved (p. 3). The Commission considers it is appropriate for DNSPs to weigh the principles based on the specific circumstances and evidence at the time — in consultation with retailers, metering parties, customers and other relevant stakeholders. Additional flexibility has been provided for retailers to seek revisions to their LMRP schedule/s (see above), and there is a best endeavours requirement on retailers to meet the interim targets (appendix A.2.4).

95 See: AGL (p. 5); Alinta (p. 3); CEC (p. 2); Energy Queensland (p. 11); ETU (p. 4); EWO (p. 2); Green Metering (p. 3); Intellihub (p. 6); SA Power Networks (p. 5); SwitchDin (p. 6).

detailed planning and scheduling of metering works is adequately covered by the more prescriptive minimum content requirements (see above).

Second, rather than a principle requiring DNSPs to allow for a reasonably consistent failure rate over time, the Commission recommends requiring approximately 20 per cent (plus or minus 5 per cent) of meters to be replaced each year. This more prescriptive approach provides greater certainty for DNSPs and affected parties to develop the LMRPs, while ensuring the replacement program is not back-ended — which would create additional risk that retailers do not have enough time to address unforeseen issues by the 2030 target.[96] Some stakeholders in discussions considered the previous drafting is too uncertain and could allow significant annual variations. The LMRP should recognise that later years may require additional work as sites with complex remediation issues are identified and addressed, under a separate regulatory process (see appendix D.3).

Third, we have sought to place requirements on DNSPs to consider and balance geographical economies and workforce/supply constraints. Broadly grouping installations by postcodes and/or meter reading routes — that, for example, have a higher proportion of meters that rely on estimated reads or use technology due for decommissioning — is likely to minimise costs and maximise the benefits of the acceleration program. This notwithstanding, requiring all meters in a city or large regional town to be replaced in one year may be more costly and challenging than spreading the installations in that city or town across several years. DNSPs should consider how to utilise local workforces in a way that avoids the need to move installers every year or a local boom-bust cycle. Telstra submits that any schedules developed must account for market deployment capacity locally, taking into account all other schedules being developed — including differences in metropolitan and regional areas.[97]

We expect explicit reference to labour market conditions for electricians and the supply of metering components will support retailers and metering coordinators in the development of the LMRPs.

### A.2.4 A performance reporting and compliance regime would provide incentives for retailers to meet the targets

The Commission's recommendations aim to ensure that every small customer either receives a metering upgrade or has an opportunity to have their meter upgraded by mid-2030. As discussed in section A.1.2, we recognise 100 per cent deployment of smart meters may not be achievable.

Transparency around the performance of retailers and metering parties, in meeting the interim targets and the 2030 goal, would promote the timely deployment of smart meters. Performance reporting can be used to enhance accountability and provide incentives to improve performance.

96 In its submission to the draft report, Vector states it is important that any accelerated rollout delivers a consistent flow of meter exchanges and avoids 'boom and bust' cycles (p. 2). PIAC suggests the schedules should front-load replacements to encourage over-achievement and provide flexibility to manage potential delays in subsequent years (p. 12). The Commission considers there should be sufficient flexibility to build-in contingencies in the development of the LMRPs.

97 Telstra submission to draft report, p. 4.

Annual performance reporting supports the AER's compliance activities over the acceleration period. Retailers would have an opportunity to provide context to the AER if they are not meeting the interim targets and, most importantly, give the AER assurances that they are on track to ultimately meet the 2030 target.

### Performance reporting promotes transparency and accountability

The Commission recommends requiring retailers to report on their performance to the AER under the current framework for retail market performance reports.[98] The AER's annual reports cover the previous financial year and are due to be published on or before 30 November each year.

Stakeholder submissions generally support the need for performance reporting to ensure compliance with interim targets.[99] AEMO highlights examples of issues the performance reporting would need to account for — including regional installations, customer switching and other reasons retailers are 'unable to complete' installations so they are not unreasonably assessed.[100]

We propose for retailers to report on their high-level performance in upgrading the retired meters in the previous period against the LMRP schedule, including:[101]

- the total number of meters installed and percentage of the interim target achieved
- the total number of sites with issues preventing installation, including where installations where unable to be carried out
- the total number of meters installed that were not functioning as required by the end of the interim period
- in the interim period, the total number of sites gained within from customers transferring from another retailer and the percentage of those metering installations replaced, and the total number of sites lost to other retailers from customers transferring to another retailer
- the total sites to be visited in upcoming interim periods.

Retailers would also provide an explanation of their performance against the interim and final targets, and an outline of their plan to get back into compliance (if necessary). This includes explaining where small customers are no longer a customer of the relevant retailer and other circumstances that may arise that mean replacing the meter was not reasonably possible.

98 Division 2 of Part 12 of the National Energy Retail Law includes an obligation on retailers to provide information and data to the AER, in the manner and form required by the AER Performance Reporting Procedures and Guidelines, relating the activities of the entity for any matters that are required by the NERR to be included in a retail market performance report. Part 10 of the NERR sets out details of matters to be included in retail market performance reports. The AER's April 2018 Performance Reporting Procedures and Guidelines set out the manner and form in which retailers must submit information and data to the AER relating to their performance under the Retail Law and NERR.

99 For example, see: PIAC (p. 12); SA Government (p. 4); SA Power Networks (p. 6).

100 AEMO submission to draft report, pp. 5–6.

101 These would be high-level indicators based on aggregated data — as distinct from granular data at a postcode or even NMI level.

We consulted on the need for upfront and clearly defined exceptions — such as for customer refusal and site access issues. Retailers were largely in favour of this approach in discussions and as submitted by Origin.[102] After further consideration, the Commission finds:

- minor divergences from the LMRP schedule for legitimate reasons should not make a material difference to the benefits of the acceleration program, so long as the retailer gets back on track and the final target is achieved by 2030
- upfront exemptions could create negative incentives for retailers to meet their targets
- processes to record and track exceptions would create administrative burdens and complexity that are not proportionate to the benefits.

We consider the contents of the AER's annual retail market performance report should include the above metrics for each retailer, and commentary on retailers' performance implementing the acceleration program — such as the reasons for any material differences between retailer results (especially on issues preventing installation). For example, the composition of retailer customers, like urban and rural, could help explain any differences.

The AER may seek further information from the retailers if, for example, a retailer's performance is an outlier and there are questions about the retailer's efforts to address customer concerns. This form of assessment would create stronger incentives for retailers to minimise issues preventing installation of smart meters.[103]

The Commission considers that non-compliance with these new reporting requirements should be subject to civil penalties, to ensure retailers provide the data and information to the AER in a timely way — consistent with the current retailer reporting requirements. Retailer performance reports to the AER must be signed by the Chief Executive Officer (CEO) or a delegate appointed by the CEO for this purpose.

In our view, it is appropriate for these new reporting requirements to be prescribed in the NERR, rather than AER guidelines. AER consultation to update its Performance Reporting Procedures and Guidelines would create an unnecessary regulatory burden and the retailer reporting requirements are only temporary.

**Compliance obligations on retailers should be proportionate**

We have sought to balance providing the certainty of a clear plan with flexibility for retailers to minimise their costs and manage changing circumstances. The proposed framework is designed to emphasise the need for retailers to report on their performance, and explain how they will get back on track if they are not meeting the targets — with the main goal to reach universal deployment by 2030 to the extent possible.

Some stakeholders submitted flexibility should be allowed for in a LMRP so that a retailer has the option to meet different metrics — such as a percentage of total meters replaced,[104] rather than the one measure of scheduled NMIs. It is argued this additional flexibility would

102 Origin submission to draft report, p. 3.

103 We consider the AER would not need compulsory information gathering powers to ensure retailers provide this information to the AER in a timely way. Retailers would have an incentive to respond to any AER questions to clarify aspects of their performance.

104 For example, in its submission to the draft report, Origin Energy considers annual volume targets are likely to be appropriate, given the relatively short timeframe to universal uptake. (p. 2)

potentially allow for materially better customer outcomes. As circumstances change, such as identifying complicated site issues not taken into account in the LMRPs, retailers could adapt their approach accordingly to maintain momentum and have time to coordinate efforts, including by third-parties.

ETU states:[105]

> Consideration should be given when enforcing compliance with the target to participants who encounter unanticipated or unavoidable roadblocks. A lack of flexibility in this regard may lead to undue pressure being placed on employees to engage in unsafe, unethical, or illegal practices in order to meet hard targets.

The Commission recommends that where a legacy meter has been scheduled for replacement in a LMRP, the retailer must:

- use best endeavours to ensure it is replaced in accordance with the LMRP schedule to meet the interim targets
- meet the final target of universal penetration of smart meters by 2030 (subject to the retailer being able to justify any failure to meet the target, based on a reasonable assessment of the circumstances).

'Best endeavours' would require retailers to do what is reasonable in the circumstances.

Further, we recommend that civil penalties apply for non-compliance with the final 2030 target, but not the interim targets. We consider financial incentives for retailers to meet the 2030 target are appropriate to support the timely deployment of smart meters. Reputational and other incentives created by performance reporting against the interim targets, as well as the need to progress the replacement program in order to meet the 2030 target, provide sufficient incentives for retailers to strive to meet the interim targets.

As noted above, exceptions to complying with the LMRP would not be specified in the NER, and would be left to the discretion of the AER to determine. If a retailer is unable to replace a meter in accordance with the LMRP, or the meter is not functioning as required, it would be open to the retailer to report the reasons to the AER. The AER would determine if the retailer's explanation for not meeting the target is justified.[106]

The Commission recommends that where a small customer has switched during the acceleration period, the new retailer must arrange for the meter to be replaced before 30 June 2030 or six months after the small customer switches retailer, whichever is later.[107] We

105 ETU submission to draft report, p. 2.

106 The Commission considers the flexibility of a best endeavours requirement and no civil penalties applying to interim targets, and reliance on AER discretion taking into account the circumstances at the time, sufficiently addresses Origin Energy's concern that DNSPs can influence retailers' performance. In its submission, Origin Energy proposes the inclusion of enhanced penalties for DNSPs who fail to provide sufficient notification to metering parties and retailers where a DNSP meter will be removed (p. 3).

107 In its submission to the draft report, SA Power Networks highlights the issue that a customer who changes retailer regularly could delay their meter replacement indefinitely — which would impact on efficiencies built into the LMRP. SA Power Networks submits: 'While some delays may be unavoidable if a customer churns retailer close to the date their meter is scheduled for replacement, as far as possible the intended replacement date should be preserved even though the customer has changed retailer.' (p. 6). The Commission considers the AER would have discretion to consider whether retailers are replacing meters in a timely way as part of its performance reporting and compliance enforcement roles. The AER would be obligated to consider the retailers reasons for not replacing the NMIs they are responsible for in deciding on enforcement action — consistent with the AER's broader enforcement strategy.

consulted on how retailers' compliance reporting should account for customer churn — including the options of classifying customer churn as an exception and requiring the new retailer to replace these customer meters within 12 months, or in the subsequent interim period.[108] However, our final recommendation provides for more flexibility for retailers to comply with the interim targets than was originally envisaged.[109] The main focus of the proposed framework is on achieving the final 2030 target.

## A.3 The Commission recommends new customer safeguards as part of the transition

The Commission considers new safeguards are required to manage customer risks associated with retailer decisions both on how they pass on meter replacement costs to customers, and to provide sufficient notification and information regarding any changes to the customer's retail pricing structure. In our view, these are crucial considerations to maintain social licence for the smart meter acceleration program.

The Commission recommends:

1. prohibiting retailers from specifically charging upfront costs for meter replacements under the acceleration deployment program (ie, NMIs retired under a LMRP)
2. requiring retailers to provide their customers sufficient notice when transitioning to a different pricing structure — ie, a 30 business day notification period, rather than the current requirement of five business days
3. providing customers with additional information on how to understand and monitor their usage and manage change — including allowing the customer to request an estimate of what their historical bill would have been under the varied tariff.

We do not consider that some individual customers should incur a one-off significant increase in costs as a result of the deployment program because it would not be consistent with current industry practice and may result in an unfair higher impact on some customers when all customers share the benefits.

Stakeholders provided significant feedback on the need for safeguards relating to the short-term impacts on customers of both bill increases associated with the accelerated deployment, and changes to the underlying network tariff structure (appendix A.3.1).[110]

Our safeguard recommendations are focused on retailer decisions to address these concerns (appendix A.3.2). Although the Commission considers the risks have a low probability of eventuating, they nonetheless have the potential to be high impact for customers — which creates a significant risk to the overall success of the acceleration program. We maintain the AER's Tariff Structure Statement (TSS) process is the appropriate mechanism to decide on network tariff assignment policies. We have considered how these recommendations would be implemented in practice, as outlined in appendix A.3.3.

108 It is noted the Commission recommends retailers should be required to track sites requiring remediation (see appendix D.3.4).

109 This simplified approach avoids the need to develop regular reconciliation processes between retailers to ensure meter replacements are assign to the correct party, as suggested by Origin Energy in its submission to the draft report (p. 1).

110 See appendices C.4 and G of the draft report.

### A.3.1 Stakeholder submissions on bill impact issues

#### Upfront cost impacts on customers

Stakeholders raised concerns about cost impacts for customers in meetings with us and submissions to the directions report. We recognise retailers are likely to face higher metering costs overall in the short term as a result of the acceleration program — compared to a system of more slowly replacing legacy meters.

In the draft report, the Commission considered that current industry practice to smooth the upfront metering costs, and socialise these costs across the entire customer base, is likely to continue and retailers will benefit from offsetting cost savings.[111]

Stakeholder submissions to the draft report generally acknowledge that although retiring legacy meters earlier than would be the case under the retailer-led deployment model would result in costs being brought forward, the economies of scale that can be captured under the accelerated deployment program will reduce the marginal cost of installations in real terms — which would benefit customers in the medium to long term.[112] This is in addition to other mitigating benefits that are expected to offset the cost of smart metering, such as remote services for energisation and de-energisation (where these services are permitted), as well as the benefits to consumers and the power system of earlier access to smart meter data and functionality.

Nevertheless, stakeholders continue to highlight the bill impact risk to consumers.[113] Alinta states 'while we appreciate the cost-benefit analysis undertaken by Oakley Greenwood (and support its conclusions), smart meters are more costly than basic (type 6) meters'.[114] ACOSS recommended the Commission should consider a range of mechanisms for 'defraying' upfront costs.[115]

#### Customer re-assignment to new tariff structures

Stakeholders identified that the accelerated deployment of smart meters could facilitate the shift of more customers to cost-reflective pricing structures sooner than expected.

Under the current network tariff framework, DNSPs are generally proposing tariff assignment policies that require sites that receive a meter exchange to be reassigned to a default cost-reflective tariff without the ability for retailers to opt-out. The AER has set this direction over time to promote network tariff reform — following previous Commission reforms. Retailer market offers, which are not regulated by the AER, are increasingly reflecting the underlying network tariff in their market contracts.

111 AEMC draft report, pp. 135–137.

112 See: Alinta (p. 10); Energy Queensland (p. 34); Momentum (p. 8); SA Power Networks (p. 15); SNAPI (pp. 5–6); SwitchDin (p. 14).

113 For example, see: ACOSS (p.20); Alinta (pp. 9–10); Energy Queensland (p. 33); IPART (p. 2); SA Government (p. 3).

114 Alinta submission to draft report, pp. 9–10.

115 ACOSS submission to draft report, p. 5.

The Commission acknowledges that automatic tariff re-assignment policies create a risk to customers, which can lead to a negative customer experience. This was a key insight of our customer research.[116] Customers may not understand how their usage patterns could impact their electricity bill if they are re-assigned 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 may be unable to shift their consumption to different times — at least in the short term.

In the draft report, the Commission considered the network pricing framework is generally fit-for-purpose; it is robust to changing circumstances and customer preferences over time, and provides flexible transitional measures. We sought feedback on possible new customer safeguard options to provide greater assurances to customers — including strengthening the customer impact principles under the TSS framework and/or prescribing a transitional arrangement in the NER.[117]

ENA and several DNSPs support our initial position to rely on the existing network pricing framework in their submissions to the draft report.[118] The AER states:[119]

> Our view is that the existing regulatory framework for network tariffs is fit for purpose, reflects the differing circumstances across distributors and the varying views across stakeholders, and can accommodate a faster smart meter rollout. … It is not clear that the AEMC's proposal to amend the pricing principles to further emphasise the need to account for customer impacts, will add value beyond the current pricing principles.
>
> … we consider retailers should be required to use customers' smart meter usage data to provide customers with further information about any up-coming retail tariff changes, and their options.

ActewAGL considers the existing tariff framework is already highly prescriptive and further regulation has the potential to increase customer confusion as well as retailer costs, which would ultimately be passed on to customers.[120] Momentum considers prescribing a transitional arrangement could create an administrative burden.[121]

Other submissions consider customer safeguards are required to address uncertainty about how customers will be transitioned to cost-reflective pricing:

- EWO states prescribed transitional arrangements could further improve consumer experiences and support consumer trust throughout an accelerated rollout.[122]

116 See Newgate Research research report, September 2021, available at: https://www.aemc.gov.au/sites/default/files/documents/newgate_research_full_research_report_-_metering_review.pdf

117 AEMC draft report, pp. 89–96.

118 See: ENA (p. 3); Endeavour Energy (p. 6); Energy Queensland (p. 25); SA Power Networks (p. 11)

119 AER submission to draft report, p. 9.

120 ActewAGL submission to draft report, p. 4.

121 Momentum submission to draft report, p. 6.

122 EWO submission to draft report, p. 7.

- The CEC submits new customer safeguards should be put in place 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.[123]
- EnergyAustralia supports additional information being provided to customers about their tariff change and considers that appropriate information on the potential impacts should provide a reasonable safeguard.[124]
- Aurora supports the introduction of a transition period before tariff re-assignment — which currently exists in Tasmania and allows for a period in which advanced meter data can provide greater certainty on whether an alternative, cost reflective tariff is suitable for a customer.[125]
- Red and Lumo considers consumers are entitled to have a basic understanding of how cost reflective tariffs work before they are placed onto them to properly respond to a sharper price signal in a manner that suits their preferences and circumstances.[126]
- Several stakeholders consider DNSP tariff assignment policies should be prescribed in the NER for a defined period.[127]

PIAC considers customer protections should focus on retail tariffs and ensuring consumer choice of retail tariff is protected.[128] Although the AEC supports the introduction of a transition period where customers could remain on their existing retail tariff arrangements, it submits network tariffs can be changed immediately without necessarily impacting customers — depending on retailer decisions.[129]

### A.3.2 New customer safeguards are required at the retail level

To maintain and build social licence for the acceleration program, we consider it will be important for:

- retailers to not levy upfront metering costs — consistent with current industry practice
- retailers to provide customers additional notification and information on tariff structure changes
- the AER to manage network tariff assignment policies as part of the TSS review process — under the current regulatory framework
- retailers to continue to compete on their service and price offerings — taking advantage of smart meters — to provide customers choice.

**The Commission is seeking to manage the customer impacts of the acceleration program**

123 CEC submission to draft report, pp. 2–3.
124 EnergyAustralia submission to draft report, p. 5.
125 Aurora submission to draft report, p. 3.
126 Red and Lumo submission to draft report, p. 5.
127 Secure Meters (p. 8); Simply Energy (p. 4); SwitchDin (pp. 9–10); Vector (p. 12).
128 PIAC submission to draft report, p. 15.
129 AEC submission to draft report, p. 2.

Submissions to the draft report highlighted that building and maintaining social licence is key to promoting the timely delivery of the smart meter program. We consider the accelerated deployment program should be designed to maximise the benefit for all system users to the extent possible to promote societal change — including fairness considerations, as suggested by ACOSS, ECA and PIAC in their submissions to the draft report.[130]

Social licence in the context of the metering review refers to the informal permissions granted by consumers for institutions to make investment decisions on their behalf. Without social licence, the smart meter acceleration program is less likely to realise the full potential of the efficiency benefits, as consumers may increasingly refuse access to their properties or be less willing to remediate their electricity boards when required.

All parts of the sector have a role to play to help customers understand and navigate the complex changes that are happening. This takes clear communication of the benefits of smart meters and trusted sources of information (see appendix C.1). Strong partnerships and coordination between DNSPs, retailers and metering parties would be crucial to maintain consistent messaging and a seamless customer experience. It would be important for the AER to monitor and provide oversight of the acceleration program to ensure successful implementation of the recommendations in this report.

**Prohibiting retailer upfront charges ensures current industry practice is maintained**

The Commission expects retailers would face higher metering costs overall in the short term as a result of the accelerated deployment of smart meters. This can include:

- Smart meter annuities: Annual charges levied by the metering coordinator that include the capital, general installation, administration, some remediation and most other install costs.
- Incidental installation costs: Upfront costs for activities not covered in the annuity — such as wasted site visits and after hours jobs.
- Remediation costs: Upfront costs a retailer chooses to pay that are not included in the annuity. Remediation may require customer consent given the meter board is their property.
- Business costs: The acceleration program may lead to increased internal administration, customer management and IT costs for retailers.

The risk of customers facing up-front costs associated with meter upgrades is low based on current industry practices, cost structures and contracts. Retailers usually face annualised charges with the metering coordinator incurring the capital and installation costs. The large majority of the total meter costs are included in annuities. Further, competition provides a discipline on retailers not to charge significantly above their marginal costs or impose up-front charges due to the material risk of losing market share.

130 See: ACOSS (p. 4; 9); ECA (p. 1; 8); PIAC (p. 11; 22).

Our understanding is that few retailers currently choose to levy up-front charges to customers. These charges are for metering parties' direct costs of performing customer-initiated work.[131]

Although these current arrangements provide some assurance, it is possible retailers will change their pricing policies and require customers to face upfront costs — even where the customer has not requested a new meter. This could jeopardise the social licence and success of the acceleration program. Retailers are not prevented from doing so under the current regulatory framework. We consider retail market competition will provide a discipline on retailer decisions. However, the risk is high impact and intervention is low or no cost if retailers maintain current practices.

Therefore, the Commission recommends transitional rules that prohibit retailers from charging upfront costs (or exit fees) for meter replacements under the acceleration program. That is, for NMIs retired under a LMRP, retailers would be unable to require these affected customers to pay an upfront, lump sum charge for costs to the retailer resulting from the installation of the smart meter. This includes meters retailers choose to replace ahead of the LMRP schedule (eg, not due to customer solar installations, or otherwise requested by the customer). Costs would instead be recovered over time — with the exception of site remediation for which other safeguards apply (see appendix D.3.5).

**Transitional measures will further assist customers being moved to a different pricing structure**

The NERR set out some minimum requirements that apply to the terms and conditions of market retail contracts. The retailer must give notice to the customer of any variation to the tariffs and charges that affects the customer. The notice must be given at least five business days before the variation in the tariffs and charges are to apply to the customer. The notice must (among other things):[132]

- specify the date on which the variation will come into effect
- identify the customer's existing tariffs and charges
- identify the customer's tariffs and charges as varied
- specify that the customer can request historical billing data and, if they are being sold electricity, energy consumption data, from the retailer.

A retailer must provide the notice as soon as practicable, and in any event no later than the customer's next bill, where the variations to the tariffs and charges are a direct result of a tariff re-assignment by the DNSP.

In practice, although DNSP assignment policies may include a 12-month transition period, retailers do not necessarily communicate the network tariff transition period to customers. Customers may receive the minimum notice period of five business days of a change to their tariff structure. In some circumstances, customers can be placed onto a different pricing

131 See, for example, Origin Energy's submission to the draft report, p. 9, and related information on their websites at https://www.originenergy.com.au/pricing/additional-charges/metering-charge-faq/ and https://www.originenergy.com.au/pricing/additional-charges/ (accessed 25 August 2023).

132 NERR cl. 46.

structure without notification or consent — depending on the timing of the tariff reassignment by the DNSP within the customer's billing cycle — in which case, a retailer must notify the customer as soon as practicable but no later than the customer's next bill.[133] IPART proposes that we remove this exception to ensure that customers are informed of changes to their retail tariffs before they occur.[134]

The Commission recommends a new safeguard to delay retailers transitioning customers to different pricing structures over the acceleration period (2025–2030). We consider:

- the current notification period of five business days is insufficient — especially given DNSP tariff assignment policies that allow for a customer transition period are not necessarily being communicated by retailers to customers
- extending the retailer customer notification period to at least 30 business days is a more effective safeguard — providing customers time to churn if they find a better offer (including a flat tariff structure), consider how to adjust their usage, and/or to make investments in household appliances that allow them to better manage their usage
- retailers should provide customers with tariff change notices regardless of the deployment type under which a meter is exchanged (e.g. customer request or new meter deployment)
- the extended notification period should apply to changes to retailer pricing structures (eg, moving from a general supply tariff to a time of use tariff) — as distinct from pricing levels (eg, prices going up due to changes in wholesale prices)
- complementary, enhanced retailer information requirements are also needed, including requiring retailers to:
  - specify in the notice that the customer can request an estimate of what their historical bill would have been under the customer's tariffs and charges as varied, compared to the bill they received under the customer's existing tariffs and charges, to the extent that the customer's smart meter data is available
  - provide supporting (generic) information to the customer on how to understand and monitor their usage (eg, apps, web portals, or in-home displays), and manage their usage to be rewarded for responding to price signals under the new tariff structure (eg, tips/ways to shift consumption).

The Commission considers a 30 business day notification period better balances the need to reduce the risk of customer bill shock and provide enough time for consumers to take action (including exploring other retailer offers), while not overly delaying scope for the customers to benefit and be rewarded for actions that, for example, better utilise existing network infrastructure. We discussed with ECA how customers may respond to the retailer notifications. Relatedly, the Essential Services Commission (ESC) of Victoria found:[135]

> … timeliness is a key principle of effective behavioural approaches. According to

133 NERR cl. 46 (4C).

134 IPART submission to draft report, p. 3.

135 ESC, Building trust through new customer entitlements in the retail energy market, Draft Decision, September 2018, pp. 63–64.

> behavioural research, a prompt to take action is most likely to be effective if it is provided as close as practical to the time the consumer is required to make and act on a decision. For example, a recent OECD report based on the telecommunications market suggests that information be provided just in time, such that it is available in the context of the critical decision point. …

Alinta does not support DNSPs assigning customers to a cost reflective tariff without retailers being able to change the retail tariff:[136]

> If customers are reassigned to cost reflective network tariffs following the installation of smart meter, retailers should not be restricted in making an alternative offer aligning with the network tariff if they choose to. Retailers should not be put in a position however of facing the cost reflective network tariff only to face delays to applying their own changes to the customer's pricing structure. Cost reflective network tariffs should only come into force once a retailer has met its regulatory obligations under the NERR and any jurisdictional requirements (such as advanced notice).

Similar feedback was provided by other retailers in a mid-June 2023 workshop. DNSPs also provided commentary on this issue in discussions, especially Essential Energy.

The Commission considers:

- The AER would have discretion to take the new safeguards into account as part of its assessment of the DNSPs' TSS proposals — noting that a final determination on any rule change would likely be made following the AER's April 2024 decisions for NSW and ACT.
- A 30 business day notification period balances the risks to retailers of a misalignment of timing with the network tariff structure and giving customers an adequate notification period.
- The majority of customers who move from a flat rate tariff to say a sun or solar soaker tariff are likely to be better off. So, retailers may not be worse off from an extended notification period.
- Retailers can adequately consider and account for forecast meter changes and the associated network tariff changes within their business models. They have been managing network tariff changes to date.

**The regulatory framework allows the AER to manage decisions on whether and how to implement cost reflective pricing at the network level**

In our view, 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 consider customers' preferences and stakeholder views in the regulatory proposals and outcomes under the NER.

136 Alinta submission to draft report, p. 8.

The regulatory process outlined below is robust to changing circumstances over time. The Commission considers AER discretion and flexibility are likely to be more appropriate in this complex and dynamic environment.

The NER require DNSPs to develop a TSS that outlines the proposed pricing structure for the next regulatory period — which the AER examines within the distribution revenue determination process. The AER must approve the TSS if it promotes the NEO and meets the specific NER requirements discussed below.[137]

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.[138] 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:[139]

- 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
- the extent to which retail customers can mitigate the impact of changes in tariffs through their decisions about usage of services.

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).[140]

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.[141]

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

137 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.

138 NER clause 6.18.5(a).

139 NER clause 6.18.5(h).

140 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.

141 NER clause 6.8.2.

written submission to the AER within its statutory timeframes, and the AER must have regard for those written submissions.[142]

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.[143] DNSPs have undertaken significant consultation, customer education and consideration of the potential impacts on customers.

It is up to retailers whether or not 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 consumers. Retailers are currently free to manage network price signals to customers how they choose as part of their market offers. This would not change under the proposed new safeguards — the focus is on providing customers adequate notification of any changes to their pricing structure.

**Retail market competition should promote customer choice of different pricing structures**

The Commission explored an option to prohibit DNSP policies to automatically assign customers who receive a smart meter within the acceleration period to a default cost-reflective tariff. Putting the onus on the market bodies and industry to demonstrate the benefits to customers of new and innovative access and pricing options may better promote customer choice and trust.

Our recommendation is to continue to rely on the AER's TSS process to make a decision on whether opt-in or opt-out provisions are more appropriate.[144] This allows for stakeholders in each jurisdiction to balance the economic and social issues based on the circumstances and customer preferences at the time to promote the long term interests of consumers.

Mandatory cost reflective pricing structures at the network level do not necessarily mean retailers cannot provide options to customers, as noted above. Ideally, retailers will offer consumers a range of services to allow them to readily select the offer that best meets the customer's needs and preferences.

Nevertheless, we have not sought to require retailers to offer customers the choice of a flat tariff structure, as suggested by some consumer groups in submissions to the draft report.[145] We consider market-based outcomes is the appropriate mechanism to promote consumer choice. Retailers have a strong incentive to gain market share by offering services customers prefer. Our focus is more on promoting transparent and understandable information on retail prices and other terms and conditions, so customers can weigh-up different options available to them and make informed decisions about their retailer service provider.

142 NER rules 6.10–6.11.

143 See appendix C.4.2 (pp. 91–92) of the draft report, which outlines case studies.

144 AEMC draft report, p. 94.

145 See: ECA (p. 11); NICE (p. 5); PIAC (p. 15).

### A.3.3 How would the safeguards be implemented

#### Prohibition on upfront and exit fees associated with acceleration program

The Commission recommends that a transitional provision is inserted under schedule 3 of the NERR that prohibits retailers from charging small customers any upfront costs or exit fees that relate to replacing a type 5 or 6 meter that is identified in a LMRP.

This prohibition would not apply to meter installations at new connections, customer request or where the meter replacement has resulted from the small customer installing equipment at the site — for example, solar panels or a battery.

The NERR allows retail contracts to include a term or condition that provides for payment of an early termination charge.[146] The Commission recommends specifically prohibiting market retail contracts from including an early termination charge associated with the acceleration program.

#### New customer notification and information requirements

The Commission recommends that a transitional provision is inserted under NERR clause 46(4) as set out below.

Retailers would be required to include the following additional information in the notices:

- that the customer can request an estimate of what their historical bill would have been under the varied tariff, compared to the bill they received under the existing tariff (to the extent that the customer's smart meter data is available)
- helpful and available information to the customer on how to understand, monitor and manage their usage.

Retailers would be required to give at least 30 business days before the varied tariff is to apply to the customer. This would apply regardless of the reasons for the tariff change — such as the underlying network tariff changing.

These amendments would only apply to small customers whose meters are replaced under a LMRP. They would cease to apply on 31 December 2030.

146 See NERR cl. 49A.

# B NO CHANGE TO INDUSTRY STRUCTURE

The 2015 *Competition in metering* rule change created a competitive metering coordinator role in the NER, and made retailers responsible for appointing a metering coordinator at each customer's connection point.[147] The Commission considers this industry structure remains appropriate in the context of accelerated deployment. The current arrangements are more likely to deliver the innovation and service benefits envisaged under *Competition in metering*, compared to changing the industry structure (appendix B.1).

In consultations throughout the Review process, some stakeholders said the previous reforms that led to a major industry restructure have not met expectations (see chapter 2). In previous stages of this Review, we had considered alternative industry structures and found that while further changes would provide some benefits, they would also introduce complexities and significantly delay smart meter deployment.

Some submissions to the draft report – primarily from consumer groups – suggest a nuanced approach to changing metering responsibilities, whereby DNSPs, instead of retailers, are responsible for appointing metering coordinators. In response to these renewed proposals, the Commission undertook further consultation and analysis (appendix B.2).

The Commission considers the proposed change would create new problems, the offsetting benefits would not be material, and our recommendations address the issues raised by stakeholders (appendix B.3 and appendix B.4). More specifically, we find:

- Implementing the proposed change would delay the acceleration program by approximately two years, or longer, because it would require additional processes to implement consequential reforms and AEMO system changes, among other reasons.
- The disruption caused by the proposed change would create significant risks and uncertainty for the competitive metering industry.
- The proposed package of reforms recommended in this final report adequately addresses the issues raised by stakeholders, without the need to change the industry structure. For example:
    - The regulatory process to accelerate smart meter deployment is designed to achieve geographical economies and support industry coordination, and is not expected to create a material administrative burden on the industry.
    - The recommended power quality data (PQD) access arrangements would enable DNSPs to access PQD with certainty and without direct charge.
    - The recommended one-in-all-in mechanism would enable meters to be exchanged where shared fusing issues are found.

In submissions, some DNSPs highlighted the unique challenges with providing metering competitively in large and geographically dispersed parts of the NEM. Essential Energy and Energy Queensland propose that DNSPs play an extended role in these regional and remote areas. We agree there may be circumstances in which DNSPs could further support industry

147 NER clause 7.2.1(a); AEMC, *Expanding competition in metering and related services* final determination, 2015.

to undertake installations as part of the acceleration program. We consider the AER's ring-fencing guideline is appropriate to facilitate these outcomes (appendix B.5).

For these reasons, the Commission recommends that the current industry structure is preferable to other industry structures, including where the DNSP would appoint the metering coordinator.

## B.1 The current industry structure enables innovative retail services

The current industry structure aims to facilitate greater innovation in metering services at a lower cost. Metering services are not characteristic of monopoly services. The competitive metering industry creates strong incentives for businesses to innovate, meet customers' preferences, and minimise costs over time – without the need for price regulation to protect consumers.

Stakeholder submissions to the Review have highlighted that the realisation of the benefits of new and innovative metering services depends on a critical mass of smart meters and data access.[148] Economies of scale are required for market participants to justify further investments in innovative customer services. 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).[149]

The Commission considers achieving this critical mass could unlock the significant customer benefits envisaged under the previous reform program. Following the acceleration program, the high penetration of smart meters would create stronger incentives for retailers to engage with customers on the benefits of having a smart meter through their service and pricing offers.

Stakeholders generally support the Commission's position of maintaining the current industry structure, including in submissions to the draft report.[150] For example, Vector states the benefits of smart meters are best delivered in a competitive environment where market competition and innovation that benefits consumers can flourish.[151]

## B.2 Some stakeholders consider an alternative industry structure has merit

While many stakeholders support retaining the current industry structure, some propose changes that would give DNSPs greater responsibility for metering.

In submissions to the draft report, PIAC, ACOSS, and SACOSS suggest an approach to changing the industry structure that we had not previously considered in depth. Under this proposal, DNSPs, rather than retailers, would be required to appoint the metering

148 AEMC, *Review of the regulatory framework for metering services* directions paper, pp. 17; 20.

149 AEMC, *Review of the regulatory framework for metering services* directions paper, pp. 18-19.

150 See: EWO (p. X); Secure Meters (p. X); Vector (p. 3). We further consulted with Intellihub on ACOSS and PIAC's proposed changes. Intellihub did not support a change to the current industry structure – noting it would cause delays and disruption.

151 Vector submission to draft report, p. 3.

coordinator. This approach would maintain metering coordinators' role and the competitive market structure.[152]

The Commission has carried out further consultation and analysis on changing the industry structure, focusing on this approach. We understand some consumer groups (particularly ACOSS) may also support, or even prefer, other DNSP-led structures with no role or a reduced role for metering coordinators. We previously considered these suggestions and found that retailers and metering parties should remain responsible for the provision of metering services for small customers, for reasons set out in our draft report.[153] However, we consider the proposal to make DNSPs responsible for appointing metering coordinators could be easier to implement than the proposals for a DNSP-led structure with a limited role for competitive metering service providers.

PIAC considers the current industry structure is not capable of accomplishing the 2030 target, or providing an efficient and effective ongoing foundation for metering services:[154]

> The source of issues with the existing framework is the industry structure itself, founded on a misconception of metering as a 'choice' product rather than a crucial piece of system infrastructure subject to required standards.
>
> … We accept that reassigning responsibilities for metering is not without costs and complications. However, there are significant cost (and risk) implications for maintaining the current structure as the issues identified in the course of this Review clearly demonstrate.
>
> … Retailer and metering provider incentives are not aligned with responsibilities or the capacity to manage system risks and transparently control costs for the benefit of all consumers. This is especially true for metering cost and cost recovery, the handling of data, and the ability to manage risks and costs related to remediation.

Similarly, SACOSS does not consider that the Review's objective would be able to achieved within the current industry structure.[155] ACOSS submits that the existing framework to deploy universal smart metering and govern the effective operation of metering and data is complex, inefficient, and not in the best interest of consumers.[156] The consumer groups' submissions also state their view that the Commission has not thoroughly assessed alternative industry structures as part of this Review up to the draft report stage, and that this may represent a significant missed opportunity.[157]

SA Power Networks states PIAC's proposal 'offer[s] an elegant way to achieve an efficient and well-coordinated rollout and resolve the root cause of key issues with the current framework like multi-occupancy premises and access to network data by DNSPs, while

152 Submissions to draft report: PIAC, p. 8; ACOSS, pp. 4-5; SACOSS, p. 3.

153 AEMC *Review of the regulatory framework for metering services* draft report, p. V.

154 PIAC submission to draft report, pp. 2; 4–5.

155 SACOSS submission to draft report, p. 5.

156 ACOSS submission to draft report, p. 3.

157 Submissions to draft report: SACOSS p. 6; PIAC, pp. 4-5; ACOSS, pp. 11-12.

preserving the fundamental elements of competition in metering and the MC role'.[158] ECA submits there is value in drawing on DNSPs' skills and experience in installing and maintaining metering equipment where it would be beneficial to customer outcomes.[159] Powermetric encourages us to consider allowing DNSPs to allocate areas for metering coordinators, while ensuring the allocation process is fair.[160]

## B.3 Changing the industry structure would not create clear benefits for customers

The Commission considers, on balance, the current industry structure remains appropriate.

Making DNSPs responsible for appointing metering coordinators could reduce the complexity of having multiple parties, create clearer accountability for the implementation of the accelerated deployment and provide some efficiency improvements. However, the disruption resulting from the proposed change would cause a delay to the universal penetration of smart meters, and create significant risks and uncertainty for the competitive metering industry. On balance, we consider that the costs of the consumers groups' suggested approach outweigh the benefits, and we outline the Commission's reasoning below.

First, we expect that implementing this change would delay the acceleration program by approximately two years, or longer, for the following reasons:

- The rule change process would require significant consultation and consideration of a range of consequential rule changes under the broader regulatory framework.
- Implementing these rule changes may require a transition period and would necessitate AEMO B2B (business-to-business) and DNSP system changes.
- DNSPs would need to undertake tender processes to engage metering coordinators.
- Although retailers would maintain responsibility for replacing meters over the transition period, they may have mixed incentives. Uncertainty created by the rule change processes may see the trend of increasing replacement rates drop back to previous levels (see Figure A.1 in appendix A).

The Oakley Greenwood cost-benefit study that we commissioned[161] highlights the sooner the goal of universal deployment is achieved, the greater the benefits to consumers (see appendix H). The transfer of metering responsibility would cause a delay that would likely diminish the consumer benefits.

Second, the proposed industry structure change could affect existing contracts and create financing uncertainty for metering coordinators. Submissions that suggested DNSPs could be responsible for appointing metering coordinators did not contemplate the impact of their proposals on the metering industry. We undertook considerable industry consultation to

158 SA Power Networks submission to draft report, p. 4.

159 ECA submission to draft report, p. 4.

160 Powermetric submission to draft report, p. 2.

161 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, 2022, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

understand the implications of the proposal, including further discussions with PIAC, ACOSS, and other affected stakeholders.

We understand it is common industry practice for retailers and metering coordinators to have long-term contracts in place which include volume commitments. These contracts allow metering coordinators to provide lower prices based on volume efficiencies and form a strong basis to finance investment. A change to the industry structure would likely disrupt these existing contractual arrangements, and could lead to significant costs and legal risks for both retailers and metering coordinators to resolve. This may not be the case for all metering coordinators. Nonetheless, it is a risk and cost of the proposed change to industry structure.

Third, we do not agree there would be significantly greater efficiencies achieved by a DNSP-led deployment program compared to the existing industry structure whereby retailers appoint metering coordinators.

We agree that making DNSPs responsible for appointing metering coordinators would potentially improve optimisation of the sequencing of meter replacements over the acceleration period – the benefits of which may be passed on to consumers. Also, the change would avoid the administrative burden and complexity of DNSPs having to coordinate input from many retailers in some states under the LMRP process.

However, we consider the recommended LMRP approach, under the current industry structure, achieves geographical efficiencies by requiring DNSPs to consider retiring meters in geographical groupings, such as suburbs or meter reading routes (see appendix A). Once the LMRPs are established, retailers should have strong competition-based incentives to minimise the costs of the smart meter deployment program in meeting their targets. Metering coordinators would further drive efficiencies to meet their contractual obligations. Conversely, for a DNSP-led accelerated deployment, monopoly regulation would need to be applied.

## B.4 Our recommendations address many issues with the current framework

The Commission considers the proposed package of reforms recommended in this final report adequately addresses stakeholder concerns relating to data access and managing multi-occupancy sites – as outlined in appendix E and appendix D, respectively.

Regardless of whether retailers or DNSPs have responsibility for metering, the Commission considers the other party would need regulated access to data to fully realise benefits. We agree with the feedback from DNSPs and consumer groups that challenges faced by DNSPs in accessing PQD have been a drawback of the current industry structure. In this report, we have recommended changes to the framework to provide DNSPs with certain and free access to PQD. We consider the arrangements outlined in appendix E, which fit within the existing industry structure, are the best way to resolve this data access issue.

We agree with stakeholder feedback that meter replacements at shared fuse sites would be a simpler process if the DNSP appointed the metering coordinator. However, only a fraction of sites are multi-occupancies, and not all of these sites have shared fusing. We consider that the one-in-all-in process outlined in appendix DX would be sufficient to manage the challenges of meter replacement at shared fuse sites. The potential improvements for multi-occupancy sites do not warrant such a material change to the industry structure.

Some stakeholders suggest that DNSPs could be allowed to appoint the metering coordinator for multi-occupancy sites only. We consider this would be unnecessarily complex – particularly considering flow-on effects on our other recommendations.

## B.5 DNSPs may further support deployments in remote and regional locations

Some DNSPs raise concerns about the higher costs and complexity of installing smart meters in regional and remote areas, and suggest drawing on DNSPs' resources to help manage these challenges. We undertook further consultation with Essential Energy, the NSW Government, some retailers, metering coordinators and the AER on this issue.

Energy Queensland notes that metering coordinators may face challenges in accelerating deployment due to the limited availability of qualified installers. Energy Queensland suggests it may be appropriate for it to enter into commercial arrangements with retailers and/or metering coordinators to undertake smart meter installations on their behalf under certain circumstances.[162]

Similarly, to address barriers to timely, universal deployment, Essential Energy proposes that the Commission should permit an extended role for DNSPs to coordinate and lead the rollout as a meter installer, while the relevant retailer and metering coordinator retain their responsibilities. Essential Energy submits this solution would allow for the efficient deployment and installation of smart meters with local crews being able to conduct site remediation and meter replacement in a single visit.[163]

The Commission agrees with Essential Energy that there may be circumstances in which DNSPs could provide services to support the accelerated deployment in remote and regional locations, to the benefit of those customers. We support Essential Energy's preferred solution, whereby DNSPs contract with and install meters for meter coordinators in such circumstances.

Essential Energy notes that they would need a ring-fencing waiver to provide such services. The AER's current ring-fencing waiver arrangements are designed to provide flexibility where it is of benefit to consumers.[164] In our view, applying to the AER for a ring-fencing waiver is appropriate, and preferable to prescribing an outcome in the NER that bypasses the AER's assessment.

We consider that the above arrangement better promotes the long-term interests of consumers than Essential Energy's 'last resort' approach – proposed as an alternative, if we

162 Energy Queensland submission to draft report, p. 8.

163 Essential Energy submission to draft report, p. 12.

164 AER, *Ring Fencing Guideline Electricity Distribution*, Version 3, November 2021, section 5.3.2.

did not agree with their preferred solution.[165] This 'last resort' approach would extend existing legacy metering services to include meter types 1–4 under certain circumstances.

### B.5.1 Ring-fencing allows for a case-by-case assessment to ensure no harm to consumers

Ring-fencing is the identification and separation of regulated monopoly business activities, costs and revenues from those associated with providing services in a contestable market. A DNSP may provide distribution services and transmission services, but must not provide other services. This does not prevent an affiliated entity of a DNSP from providing other services. However, a DNSP must not discriminate between a related electricity service provider and a competitor of a related electricity service provider.[166]

As a monopoly service provider, there is a risk DNSPs could use their position to discriminate in favour of their related parties to disadvantage competitors operating in these markets, and/or use revenue earned from regulated services to cross-subsidise contestable services.[167] The objective of ring-fencing is to provide a level playing field for third-party providers in new and existing markets for contestable services – such as those for metering and energy storage services – in order to promote competition in the provision of electricity services.

In their submissions, Essential Energy and Energy Queensland identify scenarios in which they are likely to be well-positioned to provide reliable and cost-effective services to customers in regional areas, and propose conditions that would potentially minimise the risk to competition. It is open to these DNSPs to apply to the AER for a waiver of their above obligations under the ring-fencing arrangements.

The AER considers ring-fencing waiver applications on a case-by-case basis to assess the longer-term impact on consumers based on the specific circumstances at the time. The regulatory process is not onerous. The AER is obliged to consider whether the benefit to electricity consumers of the DNSP complying with the obligations would be outweighed by the cost to the DNSP of complying with those obligations.

165 Essential Energy submission to draft report, pp. 12–13.

166 AER, *Ring-fencing Guideline Electricity Distribution*, Version 3, November 2021.

167 AER, *Electricity Distribution Ring-fencing Guideline Explanatory statement*, Version 3, November 2021.

# C IMPROVING THE CUSTOMER EXPERIENCE IN METERING UPGRADES

The Commission and stakeholders have identified several issues that arise from the current metering arrangements that impact customers' experience in smart meter deployments. The key issues identified include a lack of upfront information available to customers, delays in replacing malfunctioning metering installations, inability to request an upgrade for any reason and changes in customer tariffs triggered by metering upgrades.

This appendix outlines the Commission's final recommendations to improve customer experience by supporting improved customer awareness, explicit rights for customers to get a smart meter and improved timeliness of installations. The approach to safeguarding customers from unexpected tariff changes triggered by metering upgrades is discussed in appendix A.3.

RECOMMENDATION 2: RECOMMENDATIONS TO IMPROVE CUSTOMER EXPERIENCE

1. Enhancing the provision of information to customers and clarifying customer's rights by:
   a. requiring retailers to provide important smart meter information to small customers s prior to any upgrades in a clear, streamlined and consistent way
   b. requiring the development of a communication strategy, including the likely 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. clarifying the malfunctions exemptions process currently administered by AEMO, in its application to small customer metering installations.

## C.1 Enhancing customer information provision

### C.1.1 The Commission recommends enhancing the information provided to customers

The Commission recommends enhancing requirements for up-front and customer-friendly information to be provided to customers, to support the deployment of smart meters and to empower them to get the best value from their metering upgrades.  The suggested measures include:

1. the expansion of information that retailers are required to provide to customers before the meter upgrade takes place, as part of the information notice requirements, and
2. the development and delivery of a communication strategy for the accelerated deployment of smart meters, including the likely development of a smart energy website.

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

In the draft report, the Commission recommended an enhanced information notification requirement as part of a single notice, including minimum content requirements.[168]The report suggested that the notice be provided under all types of deployment to the customer no earlier than 60 business days, but at least ten business days, before the proposed replacement date.

Most stakeholders supported enhanced information being provided to customers prior to a meter upgrade. They generally view it as an important measure in supporting and empowering customers to make informed decisions in the accelerated deployment.[169]

Stakeholders provided  feedback suggesting adjustments to the content requirements of the notice, its timing requirement and the type of deployments that the obligation should apply to.[170] Some considered the minimum content requirements to be too onerous and that it would not support improvements in customer engagement or acceptance of smart meters.[171] Some stakeholders suggested the notice should not be required to include information on the changes to the customers' retail contracts and tariff changes resulting from metering exchanges.[172] Simply Energy state retailers often are not aware of the network tariff that the customer will be placed on.[173]

The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining indicates the need to balance providing customers sufficient notice to understand the associated changes with a meter upgrade. They also note it's possible customers forget about the proposed installation date if they receive the notice too early in advance of the installation.[174]Vector suggests that the information notice requirements should not be a pre-requisite for a meter exchange as it could limit their flexibility in undertaking meter exchanges.[175]

Vector and AGL's view are that the notice requirement should not apply to new connections, as there is no added value for these customers.[176] AGL and ECA view certain information,

168 Please see page 78 of the draft report for the minimum content requirements proposed in the draft report.

169 Submissions to draft report: ActewAGL, p. 4; AEC, p. 2; Alinta Energy, pp. 2-3; EnergyAustralia, pp. 4-5; AGL, p. 14; Green Metering, p. 13; Secure Meters, p. 8; Sense, p. 12; SwitchDin, p. 8; SACOSS, p. 9; EWO, p. 6; ENA, p. 3; SA Power Networks, p. 10; Ausgrid, p. 8; ETU, p. 13; Department of Energy and Mining, The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining, p. 6; Jen Bradley, p. 2.

170 Submissions to draft report: AGL, pp. 14-15; Vector, pp. 10-11; Simply Energy, p. 3; PIAC, p. 24; EWO, p. 6; ETU, p. 13; SwitchDin, p. 8; ECA, p. 9; Department of Energy and Mining, The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining), p. 6.

171 Submissions to draft report: AGL, p. 15; Vector, pp. 10-11; Telstra, p. 9; CEC, p. 2.

172 Submissions to the draft report: PLUS-ES, p. 19; Simply Energy, p. 3.

173 Simply Energy, submission to draft report, p. 3.

174 Department of Energy and Mining, South Australia (Energy and Technical Regulation Division), p. 6, submission to draft report.

175 Vector submission to the draft report, p. 11.

176 Submissions to draft report: AGL, p. 15; Vector, p. 11.

such as how the customer can access their smart meter data, as better suited for the Smart Energy website.[177]

### C.1.3 We recommend enhanced customer information notification requirements for improved customer outcomes

The Commission's final position is that information provided to customers regarding metering upgrades must be strengthened. The information notice should include information found in table C.1 as a minimum. One of the recommended content requirements in table C.1 is how the customer can access their smart meter data. It may also be valuable for customers to also be informed on how they can share their smart meter data with third parties. The retailer would be required to send a smart meter information notice to the customer before installation for all types of deployments,[178] except for new connections. The notice must be sent no earlier than 60 business days but at least 4 business days before the meter exchange.

The Commission considers retailers are best positioned to provide the information as they have a direct relationship with the customer in meeting their electricity needs and preferences. Receipt of up-front smart meter deployment information in a customer-friendly way will reduce confusion and enable customers to make informed decisions, helping to improve social licence and facilitate a smoother deployment.

The information notice should be delivered to the customer in their preferred method for receiving information and notification e.g. e-mail or physical mail.

Table C.1: **Proposed line items for the information notice**

| INFORMATION RECOMMENDED FOR NOTICES |
|---|
| • The reasons for the proposed meter deployment (e.g.meter failure, customer request or new meter deployment as defined in the NERR, rule 3)<br>• An indicative timeline for when the customer would receive the smart meter (this can be a date range)<br>• How the customer can access their smart meter data<br>• The customer's rights and responsibilities regarding the meter installation (including remediation work)<br>• Any upfront charges the customer will incur under their retail contract as a result of the new meter deployment<br>• Any changes to the consumer's retail contract resulting from the meter installation, including tariff changes (if applicable)<br>• 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) |

177 Submissions to draft report, AGL, p. 14; ECA, p. 9.

178 Deployment types include new meter deployment as defined in the NERR, rule 3, customer-initiated, replacement of malfunctions and potential deployments under acceleration.

### INFORMATION RECOMMENDED FOR NOTICES

- Who the customer should contact to resolve issues, including dispute resolution options
- The retailer's contact details
- Contact details of interpreter services in community languages

The information notice content requirements are unchanged from the Commission's draft position. 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. The Commission believes it will improve the customer experience as SEC Newgate Research found that:

- 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.

The Commission considers that along with providing other information, it is also important for retailers to inform customers about whether a meter exchange will lead to a change in their tariff and retail plan. This information doesn't have to include details on the specific tariff changes that will be faced by that particular customer, as this information has to be provided under the tariff change notification requirements discussed in appendix A.3.

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 I.2.

Although the Commission has recommended safeguards limiting retailers' ability to levy up-front charges, their scope may not cover all types of deployment. Hence, there is a need to require retailers to outline any up-front charges that they may levy the customer for the meter exchange, where applicable.

We recommend that the information notice be delivered by the retailer to the customers in a flexible manner. The proposed timeframe of 60 to 4 business days before a meter exchange should enable customers to receive the information promptly while providing significant 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.

Stakeholders in consultation said that customers may forget about their upcoming meter upgrades, and may need more than one notice as a reminder closer to the installation date. Although customers could receive a notification far in advance of the installation date, they are expected to be reminded of the upgrades through the subsequent planned interruption notification arrangements under rule 59C or rule 90 of the NERR.

The Commission considers retailers could use an SMS reminder in addition to the required information provision to support improved customer experience. The Commission considers that it is also important for the notice to be provided to customers prior to the meter exchange in order for it to be able to deliver the intended social licence outcomes.

### C.1.4 A communications strategy would support acceleration

The Commission recommends a communication strategy for the accelerated deployment be developed and implemented before the commencement of the LMRP (i.e. before 2025). A strategy would help support better customer awareness, and improve customer experience and social licence. It would also provide context for the information that retailers provide their customers, particularly with the removal of customers' right to opt-out of a smart (Type 4) meter. A Smart Energy website, as proposed in the draft report, could be one element of the strategy.

### C.1.5 Stakeholders support a smart energy website and active communication

Most stakeholders support the development of a Smart Energy website proposed in the draft report and provided their views on its content, including:[179]

- reasons for the accelerated deployment, with some stakeholders suggesting that customers should be made aware that accelerated deployments are mandated under the regulatory framework
- the timing schedule of smart meter deployments
- what customers can expect, such as potential tariff changes and specific services that a smart meter enables
- an explanation of no opt-out of a smart meter
- tailored information targeted to real estate agents and landlords, particularly regarding site remediation, on how they may need to be involved in the installation process at sites occupied by renters
- how customers can receive general and financial support with site remediation.

Some retailers view the content for the website should be developed collaboratively with the industry so that the messaging is consistent across retailers and can refer to the website in their information notice to customers.[180] Parties stakeholders consider best placed to provide

179 Submissions to draft report: Red and Lumo, p. 3; SwitchDin, p. 9; EnergyAustralia, pp. 4-5; AGL, p. 10; ECA, pp. 2, 10; Origin, pp. 1,6,7; PIAC, p. 21; ActewAGL, p. 4; AER, p. 8; PIAC, p. 21; Simply Energy, p. 3; AEC, p. 2; Alinta Energy, p. 7; Momentum Energy, p. 6; Sense, p. 12; TasNetworks, p. 3.

180 Submissions to draft report: Origin, pp. 6-7; Red and Lumo, p. 3; Simply Energy, p. 3.

broad communication to customers regarding the accelerated deployment include the government, AER, ESB, or an industry body such as ECA.[181]

Stakeholders, including consumer groups, retailers, metering parties, DNSPs and the AER note the need for a communications campaign in advance of customers being notified of a meter upgrade via their retailer. They generally view it as essential that customers are aware of the reasons for accelerated deployment, what they may expect, the benefits of smart meters and their role and responsibilities to build consumer support and acceptance of smart meters.[182] Many believe that the government should lead the campaign.[183]

### There is a need to deliver a communication strategy, including a Smart Energy website

The Commission recommends the collaborative development of a communication strategy to provide customers with consistent and customer-friendly information about the smart meter deployment. This could potentially be Government driven, through the Energy and Climate Change Ministerial Council, drawing on existing jurisdictional and regulator information sources.[184] The accelerated deployment of smart meters is a critical opportunity for governments, industry and market bodies to work together to further build and establish the social licence that is required for both the accelerated deployment and for the energy transition more broadly. The industry's involvement in its development would be valuable in gathering practical customer insights and helping refine the development and implementation of the strategy.

The communication strategy should provide consistent and user-friendly and relevant information, including but not limited to:

- the deployment of smart meters taking place
- the role of smart meters in the energy transition
- the benefits of smart meters to the electricity system
- how customers can make the best use of smart meters
- roles and responsibilities of customers and industry participants for remediation and regarding notices.
- description of the different types of cost-reflective tariffs and how customers could make the best use of each.

Among other approaches, the strategy could include the development of Smart Energy website. The website would play an important role in the strategy to support customers and

181 Submissions to draft report: Alinta Energy, p. 7; Red and Lumo, p. 3; Green Metering, p. 13; Intellihub, p. 7; ECA, pp. 9-10; PIAC, p. 21; SA Power Networks, p. 3; The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining, p. 5; Telstra, p. 9; SwitchDin, p. 9; PLUS ES, pp. 20-21.

182 Submissions to draft report: Origin, p. 1; Red and Lumo, p. 4; CEC, p. 2; Simply Energy, p. 4; ActewAGL, p. 3; EnergyAustralia, p. 5; Sense, p. 12; SwitchDin, p. 9; Momentum Energy, p. 4; ACOSS, p. 6; ECA, pp. 2-3; PIAC, p. 16; SACOSS, p. 9; Energy Queensland, p. 15; TasNetworks, p. 3; Ausgrid, p. 8; Telstra, p. 9; Heather Merran, p. 5; AER, p. 8; ETU, p. 9.

183 Submissions to draft report: Origin, p. 1; Red and Lumo, p. 4; Simply Energy, p. 4; ACOSS, p. 17; ECA, pp. 2-3; SACOSS; p. 3.

184 For example: https://www.energy.nsw.gov.au/households; https://www.energy.vic.gov.au/for-households, https://www.sa.gov.au/topics/energy-and-environment; https://www.qld.gov.au/housing/buying-owning-home/energy-water-home/electricity, https://www.recfit.tas.gov.au/household_energy; https://www.energy.gov.au/households; https://www.aer.gov.au/consumers/my-energy-service.

the success of the accelerated deployment. The website could enable customers to access relevant information from an independent and trusted source in a transparent and customer-friendly manner. It would be more appropriate to consider the development of the smart energy website as a component of a communications strategy instead of a standalone regulatory requirement.

The Commission considers an approach to considering the communication of meter deployments to customers is important as it will enable a more considered and planned approach for informing customers to be developed and implemented. It will also allow the communications approach to take into account customers' journeys and experience of different types of customers, and lessons learned from other types of infrastructure deployment to customers in the past. The Commission views building customer trust and social licence before the acceleration period to be crucial for supporting a successful smart meter deployment. Customers need to be informed of the smart meter deployment, the role of smart meters in the energy transition and ultimately what it means for consumers. As gathered from an ESB customer journey workshop on smart metering, ways to build customer trust in the accelerated deployment include:[185]

- increasing customer knowledge of the benefits and necessity of acceleration
- clearly communicating the details of the change and how customers can prepare for it.

## 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 remains unchanged from the draft report.

### C.2.1 There is concern some retailers are 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 retailers' 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

185 Energy Security Board, *Customer insights collaboration*, accessed 11 July 2023.

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. However, the service benefits the consumer and the request should not go unmet.

### C.2.2 Stakeholders support customers being able to get a smart meter for any reason

Most stakeholders agree that customers should be able to obtain a smart meter even when it is not associated with a connection upgrade or a consumer energy resource (CER) installation. They generally believe it would empower customers and increase engagement with the energy market.[186] SA Power Networks suggests that customer-initiated deployments should be able to be deferred to the scheduled replacement date under the LMRP.[187] Some stakeholders oppose compulsory customer-requested meter upgrades, stating that meter deployments should remain driven by retailers, as removing retailer discretion could cause inefficiencies and add costs with accelerated deployment if is it geographically based.[188]

### C.2.3 Customers should receive smart meter upgrades upon request

The Commission recommends that customers receive a smart meter upon request. The Commission considers that customer-initiated deployments should not be deferred to the scheduled replacements under the LMRP, as suggested by some stakeholders. Rather, the meters should be replaced in line with the appropriate timelines set out in the NER for installing meters upon customer requests.[189] 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.
- Improving customer experience by allowing customers to take advantage of tariff options.
- Improving customer satisfaction and experience in meter upgrades, especially where customers themselves have requested an upgrade.
- Empowering customers 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 Implementation of a provision to request and receive a meter for any reason would involve changes to the NERR

This recommendation would be implemented as a new provision in the NERR to explicitly recognise a 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

186 Submissions to draft report: ActewAGL, p. 4; Aurora Energy, p. 3; Energy Queensland, pp. 4-5; Origin, p. 7; Simply Energy, p. 4; Momentum Energy, p. 6; PLUS ES, p. 21; Green Metering, p. 14; Secure Meters, p. 8; SwitchDin, p. 9; Vector, p. 11; EDMI, p. 12; EWO, p. 7; ECA, p. 10; PIAC, p. 21; Ausgrid, p. 9; SA Power Networks, p. 10; The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining, p. 7.

187 SA Power Networks, submission to draft report, p. 10.

188 Submissions to draft report: Alinta Energy, p, 7; SNAPI, p. 4; ETU, p. 15; Telstra, pp. 9-10; Network of Illawarra Consumers of Energy, p. 5.

189 Under clause 7.8.10A of the NER, where a small customer has requested a connection service, a meter must be installed within 6BD from when a retailer is informed that the connection service is complete if the retailer does not have an agreed installation date with the small customer. Under clause 7.8.10B and 7.8.10C, where a connection service is (not) required, a meter must be installed within 15BD of a customer's request for a meter installation if the retailer does not have an agreed installation date with the small customer.

requests being applicable. The Commission anticipates this would 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, see amendment number 26 in table I.2.

## C.3 Reducing delays in the installation of smart meters

### C.3.1 A new approach for malfunctioning meters is required for timely replacements

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:

- Separating the definition of malfunctions into two categories: 'individually identified malfunctions' and 'malfunctions identified through statistical testing' (family failures).
- The replacement time frame for individual failures and family failures to be 15 business days and 70 business days, respectively.
- Introducing requirements to the exemption process for family failures.
    - Metering coordinators must provide AEMO with a rectification plan as a prerequisite to receiving an exemption to the 70 business-day family failure timeframe.
    - In assessing an exemption and degree of extension beyond 70 business days, AEMO is to consider:
        - The size of the family failure and circumstances faced by the MPs
        - The nature of the malfunction (e.g. safety concerns, accuracy issues)
        - Any previous extension granted.

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

Under the current arrangements, metering coordinators 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 metering coordinator 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 metering installations, with lengthy time extensions sought under the AEMO exemption framework. Information provided by AEMO indicated that as of April 2023, around 300,000 malfunctioning meters had been granted exemptions under AEMO's metering installation malfunction exemption framework. Out of these meters, around half  were family failures of Type 4-6 meters as a result of sampling testing.

### C.3.3 Stakeholders generally support creating two separate categories of malfunctions but thought more flexibility is required for family failures

In the draft report, the Commission recommended the removal of the exemption process in addition to introducing separate malfunction categories and respective replacement timeframes (15 business days for individual failures and 70 business days for family failures). Stakeholders had mixed views across these recommendations in submissions to the draft report.

Stakeholders generally support creating two separate categories of malfunctions and the timeframe for individual failures.[190] Intellihub supports the proposed timeframe of 70 business days for family failures.[191] Energy Queensland and Essential Energy support the removal of the malfunctions exemption process and Vector thinks there is little value in retaining the exemption process for individual failures.[192] Many, primarily retailers and metering parties, say that the flexibility that the exemption process provides is necessary for certain circumstances. For example, exemptions are needed for family failures with significant meter volumes and/or malfunctions and at sites that have access or site remediation issues.[193] Vector notes that not all meters in a family are faulty when identified via sample testing, but are found to likely operate outside accuracy requirements in the future.[194]

### 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 Family failures should have an appropriate and flexible replacement time frame requirement

The Commission considers that a default timeline of 70 business days coupled with a more clearly defined exemptions process would help support a more timely and orderly replacement of meters family failures.

Some family failures can be reasonably expected to be replaced within the 70 business day timeline, and as such, would benefit from a clearly defined timeline. The Commission also considers that the flexibility provided by the exemption process provides should be retained, to reflect the challenges that may be faced in undertaking some meter changeovers, and to overcome the limitations associated with setting a single timeframe for family failures. The metering coordinators could be prevented from meeting the 70 business day replacement timeframes due to reasons, such as:

190 Submissions to draft report: ACOSS, p. 19; Origin, p. 7; Vector, p. 11; The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining), p5.

191 Intellihub, submission to draft report, p. 6.

192 Submissions to draft report: Energy Queensland, p. 2; Essential Energy, p. 8; Vector, p. 11.

193 Submissions to draft report: Origin, p. 7; Vector, p. 11; Aurora Energy, p. 3; The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining, p. 5; EnergyAustralia, p. 2; ACOSS, p. 19.

194 Vector, submission to draft report, p. 11.

- circumstances out of metering coordinator control that prevent meter upgrades, for example, where a customer's site has defects
- the size of a family is so large that it cannot be reasonably expected to be replaced within 70 business days.

Notwithstanding the need for the exemption arrangements, the process for seeking an exemption needs to be more clearly defined to reduce its administrative burden and to help improve the timeliness of the meter replacements. To this end, the Commission recommends that metering coordinators must seek an exemption prior to the expiry of the timeframe and must provide AEMO with a plan for the rectification of the metering installation prior to being considered for an exemption. For further details, please seeappendix C.3.1. Legal changes required to enable these measures, including different timelines, are outlined in the indicative table I.1.

Under the proposed approach, the length of the exemption that AEMO provides would be tailored to metering coordinators' individual unique circumstances and reasons for not meeting the 70 business day timeframe for family failures. In granting an exemption for family failures, AEMO should take into account the size of the family failure, the nature of the malfunction if provided, the effectiveness and timeliness of proposed rectification under the rectification plan and any previous exemptions granted.

The Commission also expects there to be less of a need for exemptions given the reduced need for testing legacy meters during the acceleration period.

### C.3.6 Legacy meters exempted from malfunctions timelines to be captured in the LMRP

As indicated in appendix C.3.2, there is likely to be a substantial number of unresolved malfunctioning meter installations (Type 4-6) that have an exemption from AEMO at the commencement of the LMRP. The Commission considers that the legacy meter (type 5 &6) NMIs with exemptions granted by AEMO should be included for replacement under the LMRPs. Irrespective of any extensions granted by AEMO, retailers would be obliged to replace these NMIs within 12 months from their retirement.  This would allow for metering upgrades to occur in a coordinated and efficient manner.  However, the inclusion of these NMIs in the LMRPs should not exempt the metering coordinators from the existing obligations to replace malfunctioning metering installations, including where an extended timeline has been granted by AEMO. This means retailer and metering coordinator obligations to replace malfunctioning type 5 and 6 meters — under the LMRPs and the exemption AEMO provides, respectively — may apply concurrently. Replacement should occur at the timing required under either obligation that prompts a more timely replacement.

The Commission doesn't consider there is a need for LMRPs to capture the malfunctioning metering installations with type 4 or 4A meters. While it may be efficient for metering parties to replace malfunctioning Type 4 and 4A meters alongside legacy meters, these replacements don't fall under the LMRP.  The LMRP is focused on upgrading legacy meters to type 4 and 4A meters. The appropriate approach and timeline for replacing malfunctioning type 4 and 4A meters is a matter for metering coordinators and AEMO.

Transitional arrangements may be needed to support the application of the revised malfunctions' framework recommended in this report to malfunctioning meters with existing exemptions.

### C.3.7 Implementation would involve changes to the NER and procedure of AEMO's exemption process

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 metering coordinatormust 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 metering coordinator has become aware that repairing the meter requires interrupting supply to another customer, 30 business days after the metering coordinator has become aware of the need for that interruption unless the site is subject to the multi-occupancy scenario outlined appendix D.6.5. of this report, in which case that framework would 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 provider 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 metering coordinator 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 metering coordinator has been notified unless a site is subject to the multi-occupancy scenario outlined in appendix D.6.5. of this report, in which case that framework would apply to that site instead of this clause. This category would cover malfunctions generally known as family failures.
- Metering coordinators can apply to AEMO for an exemption from the time frame requirements for small customers' metering installations. Metering coordinators must provide AEMO with a rectification plan for how they propose to address the reasons for being unable to install the meter before an exemption is obtained and before the expiry of the replacement timeframe. AEMO must consider the following factors in assessing an exemption request:
  - the size of the family failure
  - the nature of the malfunction
  - the effectiveness and timeliness of the proposed rectification under the rectification plan

- any previous exemptions that AEMO has granted
- other factors that AEMO considers relevant (eg. metering coordinator's resourcing capacity).

The Commission has also recommended adopting different approaches toward testing and inspection arrangements for legacy and smart meters. Testing and inspection would no longer be required for legacy meters during the acceleration period whereas the inspection and testing requirements would continue to apply to smart meters.

# D REDUCING BARRIERS TO INSTALLING SMART METERS AND IMPROVING INDUSTRY COORDINATION

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

This appendix outlines the Commission's final 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 of smart meters across the NEM by 2030 and support a better customer experience.

### RECOMMENDATION 3: FINAL RECOMMENDATIONS TO MAKE IT EASIER TO DEPLOY SMART METERS

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

Lowering the barriers to deploying smart meters, through:

1. removing the option for customers to opt-out of a new meter deployment (as defined in the NERR, rule 3)
2. reducing the number of notices to be sent to customers by their retailers before a new meter deployment from two to one
3. enabling processes to encourage customers to remediate and to track customer sites defects
4. proposing arrangements to better support vulnerable customers in addressing defect issues preventing metering upgrades
5. proposing a review of jurisdictional/DNSP regulatory arrangements to:
    a. identify and implement adjustments that could reduce the need for and cost to customers associated with site remediation
    b. enable metering parties to undertake minor remedial work without requiring prior customer approval
6. retaining the option to disable remote communications of smart meters.

Facilitating better cooperation through:

1. enabling measures to support improved industry coordination in meter upgrades for customers with shared fusing scenarios via a 'one-in-all-in' approach

2. proposing a review of jurisdictional arrangements to allow contestable metering parties to appropriately gain access to sites currently secured by a DNSP locking system.

Consumer safeguards against risks during and following the installation process, such as the risk of upfront retailer charges and automatic reassignment to a new tariff structure, can be found in appendix A.3.

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

### D.1.1 The Commission recommends the removal/exclusion of the opt-out provision alongside the introduction of consumer safeguard measures

The Commission recommends:

- the removal of provisions under NERR Rule 59A that allow customers to opt-out ofnew meter deployments as defined in the NERR, rule 3
- that provisions enabling customers to opt-out of deployments under the acceleration program should not 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 and introduce safeguard measures for acceleration address concerns regarding customer harm in meter exchanges. Our final recommendation promotes consistency of approach and harmonisation of customer rights across different metering deployment types.

### D.1.2 Some customers can currently opt-out of new meter deployments under specific circumstances

Rule 59A of the NERR allows customers to opt-out of a new meter 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 new meter deployments in scenarios where customers' meters were still functional to preserve the option for customers to retain their existing meters.[195]

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. This authorisation is not included in standard retail contracts. However, feedback from stakeholders has highlighted that the majority of market retail contracts do authorise meter changeovers without an opt-out option. In the jurisdictions where NECF applies, 78 per cent of the small residential customers are on market retail contracts.[196]

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

196 The NECF currently applies in the Australian Capital Territory, Tasmania, South Australia, New South Wales, Queensland and to a limited extent in Victoria (Chapter 5A of the NER only).

### D.1.3 Most stakeholders support no opt-out of smart meter deployments

The Commission sought stakeholder feedback in the draft report on whether the provision enabling customer opt-out ofnew meter deployments as defined in the NERR, rule 3 should be removed. The draft report also recommended that opt-out provisions for smart meter deployments required under the LMRPs shouldn't be introduced.

Stakeholders overwhelmingly support the no opt-out approach. They consider it would improve the efficiency and cost-effectiveness of meter deployments by reducing the number of wasted or multiple site visits, particularly in multi-occupancy sites.[197] Some stakeholders note that there is a need for appropriate consumer protections, such as management of remediation costs if there is a site defect, and a transition to cost-reflective tariffs so customers are not made worse off.[198]

A limited number of stakeholders raised concerns, considering that disallowing opt-out would remove customer choice, risk harming social licence and disadvantage customers in regional and rural areas with no telecommunications network.[199]

### D.1.4 Opt-out could lead to inefficiencies and inconsistencies

The Commission considers that maintaining or enabling new 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 a smart meter deployment as required under LMRPs is expected to:

- impact the efficiency of the deployment and jeopardise the level of acceleration and achievement of an overall uptake, because some customers may choose to opt-out of receiving upgrades
- introduce additional steps in the deployment of smart meters which would add further complexities to the planning and execution of legacy meter retirement plans
- create inconsistencies in the rights of customers to opt-out. 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. Removing opt-out only for customers on shared fuses would lead to an inconsistent approach, and potentially cause customer confusion
- give rise to perverse outcomes, as customers choosing to opt-out of a meter upgrade could still face the costs associated with a 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.

197 Submissions to the draft report: ActewAGL, p. 3; Alinta, p. 2; Momentum Energy, p. 2; Origin, p. 4; Evoenergy, p. 4; EDMI, p. 10; SwitchDin, p. 7; Telstra, p. 6; Green Metering, p. 8; PLUS ES, p. 11; Energy Queensland, p. 4; Ausgrid, p. 6; AGL, p. 9; TasNetworks, p. 2; SAPN, p. 8; CEC, p. 2; Network of Illawarra Consumers of Energy, p. 4; ETU, p. 10.

198 Submissions to the draft report: EWO, p. 5; PIAC, p. 15.

199 Submissions to the draft report: PIAC, p. 14; ACOSS, p. 5; Simply Energy, p. 3; Origin, p. 4; SwitchDin, p. 7; Essential Energy, pp. 11-12; EDMI, p. 10.

Further, as part of the package of reforms, the Commission also recommends safeguards and measures to improve customer experience in the accelerated deployment. These include measures to safeguard customers from bill shocks, such as protections from up-front charges and enhanced notification requirements for tariff changes and meter exchanges. We expect these safeguards to largely address the concerns regarding smart meter deployments. 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. The Commission acknowledges that some customers may wish to opt out of a smart meter deployment in order to avoid remediation costs. It should be noted that the removal of the ability to opt-out would not mean customers are required to undertake remediation — customers have the choice as to whether to remediate their site defects. This is because site remediation relates to work on the customer's installation, which is the responsibility of the customer and beyond the scope of the NEL.

### D.1.5 Implementation considerations

Notwithstanding these safeguards, the Commission recognises that some customers could refuse site access for a metering upgrade. Under such circumstances, obliging a customer to accept a metering upgrade may pose challenges to social licence as well as to customer and installer 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.

We expect that a proportion of sites won't get upgraded for reasons outside of retailer and metering coordinator control. A smart meter with remote capabilities disabled (Type 4A) is available for customers if they oppose one with remote capabilities enabled (Type 4). Reasons outside of retailer and metering coordinator control may include inability to obtain access for a metering upgrade, or an owner's unwillingness to undertake necessary remediation.  This will be taken into account by the AER when considering where there is a reasonable excuse for failing to meet deployment targets.

Details on proposed changes to the NERR to remove the existing opt-out provisions are provided in Table I.2.

## D.2 Retailers to provide one notice for smart meter deployments, outlining relevant information for customers

### D.2.1 The Commission recommends reducing the number of retailer notice

The Commission recommends reducing the number of notices a retailer provides a small customer when undertakingnew meter deployments under rule 59A — this is a change from two notices to one. The single notice should be delivered to customers in accordance with their preferred approach to receiving bills. This notice requirement would be the same as the proposed smart meter information notice requirements found in appendix C.1.3.

### D.2.2 There is strong stakeholder support for a reduced number of notices

Stakeholders in their submissions to the draft report generally reaffirm the strong support for the reduction of retailer notices as initially expressed in the directions paper. Some stakeholders offer condition support or oppose the draft recommendation.

PIAC are supportive provided that "…this notice is accompanied by independent information outlining the need for improved metering standards and available protections to defray remediation costs."[200] Retailers generally thought that fewer notices would support greater flexibility and reduced administrative burden and cost.[201] The South Australian Department (Energy and Technical Regulation Division) questions whether it is appropriate to reduce notices as, in its experience, some customers are not provided sufficient notice or made aware of smart meter installations and consequent changes to electricity accounts.[202] ECA considers both paper and digital forms of the notice could support social licence of the accelerated deployment. In addition, the ECA suggested that reminder notifications would act as a safeguard in case a customer misses, forgets or loses the original notice.[203]

### D.2.3 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 an improved customer experience. It would reduce customer confusion and regulatory burden by reducing the duplication of information provision for new meter deployments and enable greater flexibility, planning and coordination. It would also promote consistency of information provision for all metering installation types and simplify arrangements. The Commission considers retailers could use an SMS reminder in addition to the required information provision and/or PIN to support improved customer experience.

### D.2.4 Implementation considerations

Appendix C.1.3. 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 days and not less than 4 business days before the proposed meter installation date for all deployment types except new connections.

## D.3 Supporting greater success in installations for sites with defects

### D.3.1 The Commission has limited power to address some key site remediation issues

Site defects present a significant barrier to the successful installation of smart meters. As the cost of remediation typically falls on the customer, this can disproportionately affect access to smart meters for financially disadvantaged customers.

To promote greater levels of site remediation by customers and more equitable deployment of smart meters, the Commission recommends:

200 PIAC, submission to draft report, p. 16.

201 Submissions to the draft report: Alinta, p. 7; Aurora, p. 3; Momentum Energy, p. 2; Vector, p. 10; Telstra, p. ACOSS, p. 5.

202 South Australian Department (Energy and Technical Regulation Division), submission to draft report, pp. 5-6.

203 ECA, submission to draft report, p. 5.

- a process to encourage customers and landlords to remediate defects and facilitate the industry to keep records of customer site defects
- governments consider arrangements, including financial support for customers to undertake site remediation
- jurisdictions to consider reviewing their legislative arrangements that drive the need for remediation, including amendments to Service and Installation Rules

To support an efficient deployment of smart meters and provide clear rights for customers and metering parties in undertaking remediation work, the Commission also recommends that:

- while customers remain responsible for remediating sites, jurisdictions could consider reviewing their legislative arrangements to provide metering parties with access rights, as well as rights to undertake some remedial work on the customer installation without requiring prior customer consent.

Under the existing arrangements, customers will continue to face costs in undertaking the remediation work necessary to enable metering upgrades. Cost issues 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 smart meter deployments. Vulnerable customers, such as low-income families, would face greater risks of missing out. This may result in an inequitable and non-uniform deployment of smart meters as 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 their ability to afford site remediation.

Site remediation is part of a customer's installation. Most aspects of customer installations are not within the scope of matters that can be addressed by the NER.[204] It is therefore not possible for the Commission to make rules to assist consumers with remediation costs by, for example, distributing remediation costs across all customers so that everyone pays the same amount, or through targeted assistance to vulnerable consumers funded by the total customer base.

### D.3.2 Site defects are a barrier to successful metering upgrades

Major defects in the customer's electrical installations can often prevent metering installations. For example, insufficient size and poor condition of the meter panel and wiring in the meter board. The rates of major site defects vary across jurisdictions, but the Commission expects major site defects to be encountered in approximately 10 per cent of sites. Minor defects are likely more common. For example, asbestos in the meter panel and need to replace and/or relocate a fuse. 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. Metering parties are also not able to undertake remedial work without customer consent.

204 NEL, Schedule 1 — Subject matter for the NER.

Often, customers or service providers don't undertake the remedial work required to enable meter replacements. Particular groups of customers, such as those living in social housing, those with low incomes and renters may also not be in a position to readily remediate.

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. Site defects result in unexpected costs and delays for the customer. Defects can also lead to inefficient deployment because the current arrangements don't support efficient management and tracking 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.

### D.3.3 Stakeholders want site remediation issues progressed

The Commission's draft report proposed a site defect tracking and notification process, and suggested Governments could consider funding arrangements to support remediation.

Most stakeholders support implementing a process for the tracking and notification of site defects noting it would reduce wasted site visits, reduce costs, provide useful information and support better management of site defects.[205] The feedback also suggested amendments to different parts of the proposed process. Stakeholders provided suggestions regarding:

- the key pieces of site information that should be recorded
- whether the information should be recorded towards the start or the end of the notification process
- where the information should be stored
- which party should be responsible for updating site information
- which party should be responsible for issuing defect notices to customers
- whether the customer should be responsible for informing retailers about the status of remediation
- managing the issue of a customer switching to a different retailer (FRMP churn) and a change in the customer at a NMI/premises (customer churn) part-way through a notification process.
- timeframe obligations on parties.

Essential Energy and the ETU note that the recorded site information could help governments to identify and support (vulnerable) customers.[206] Several stakeholders were concerned that

205 Submissions to draft report: Alinta, p. 6; Aurora, p. 3; Momentum Energy, p. 2; Origin, p. 4; Simply Energy, p. 2; AGL, p. 11-12; EDMI, p. 11; SwitchDin, p. 7; Vector, p. 8; PLUS ES, p. 12; Intellihub p. 6; EWO, p. 5; ECA, p. 6; Essential Energy, p. 10; Energy Queensland, p. 4; Ausgrid, p. 6; ETU, p. 11.

206 Submissions to draft report: ETU, p. 11; Essential Energy, p. 10.

the proposed process would not sufficiently address the site defect issues, as it would not ensure customers rectify their site defects.[207] A few stakeholders oppose the proposed process. They generally consider it does not improve handling of site defects and additional measures are required.[208]

Many stakeholders think that it is important to address site remediation issues for successful and equitable accelerated deployment of smart meters. Recognising the limitations of the national framework, some urge governments to provide financial support to customers. They note it as critical for vulnerable customers, such as those in social housing and/or who are unable to afford site remediation, particularly if costs are substantial and upfront.[209]

### D.3.4 Development and adoption of a process to encourage customers to remediate site defects and enable record keeping of customer site defects

The Commission recommends implementing the proposed customer notification and record-keeping process where customer site defects are encountered (see figure D.1). The process should be introduced as an ongoing arrangement and apply to all types of small customer 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 would:

- 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[210]
- support greater transparency of site defects and improved deployment efficiencies through a reduction in wasted site visits.

Figure D.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. The proposed process has been revised following stakeholder feedback on the draft report.

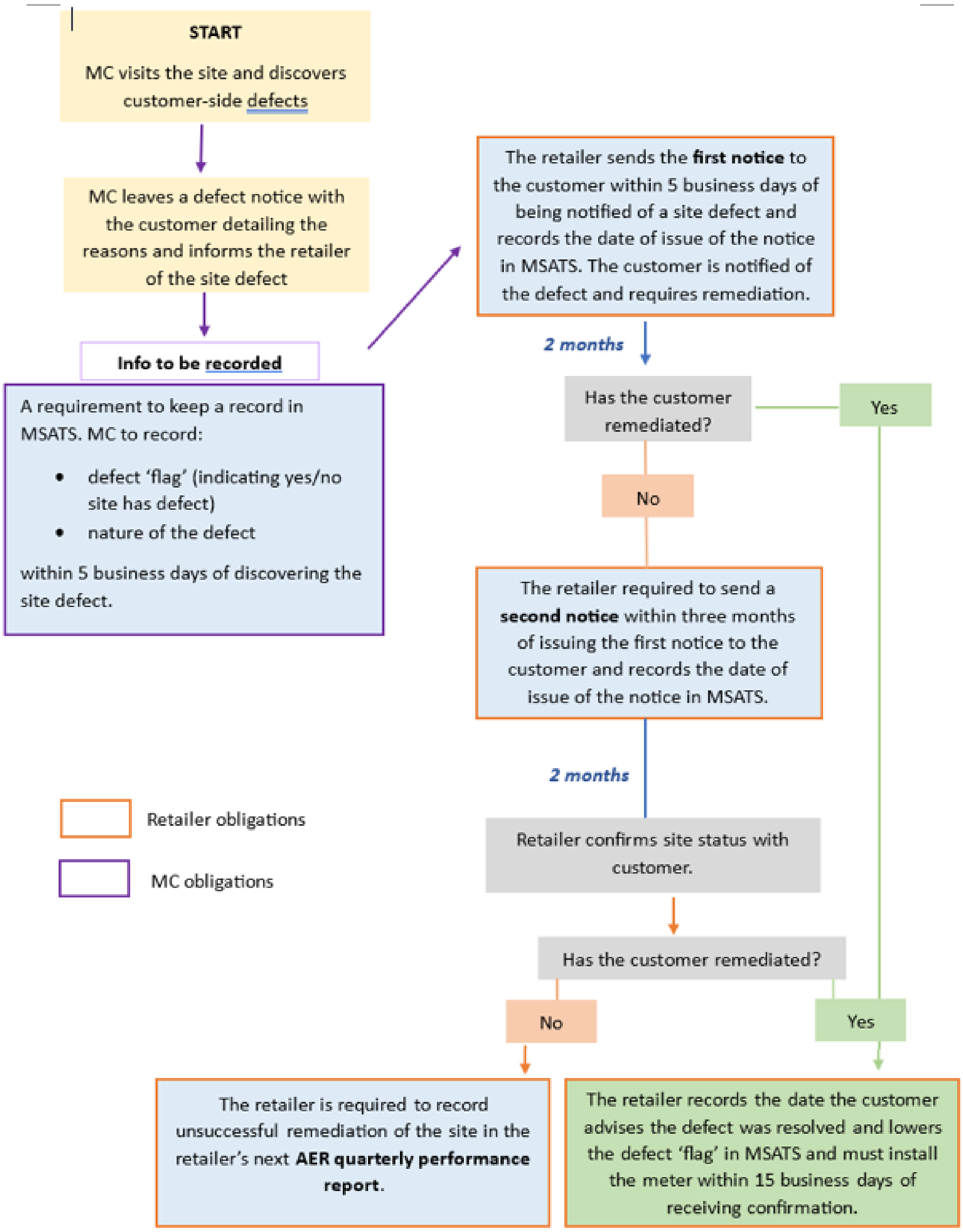
207 Submissions to the draft report: Energy Australia, p. 3; Energy and Water ombudsman, pp. 5-6; Momentum, p. 5.

208 Submissions to draft report: ACOSS, p. 5; PIAC, p. 17; Telstra, p. 7.

209 Submissions to draft report: EnergyAustralia, p. 3; Momentum Energy, p. 2; Origin p. 1; Intellihub, p. 7; Powermetric, p. 3; Red/Lumo, p. 4; Simply Energy, p. 1; TasNetworks, p. 2; PIAC, p. 18; PLUS ES, p. 14; ActewAGL, p. 3; Alinta, p. 6; ACOSS, p. 5; ECA, p. 7-8; Energy Queensland, p. 4.

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

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




AEMC

The Commission acknowledges that the tracking and notification process is likely to only partially resolve remediation issues experienced in the deployment. However, we consider it would be a valuable mechanism for addressing site remediation issues. We expect it to support greater levels of remediation and improve the efficiency of the deployment and the management of defects.

### D.3.5 Detailed process for handling site defects

We recommend 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 D.1, we recommend that:

1. **If the metering coordinator discovers a defect with a site:**
    - The metering coordinator 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 metering coordinator, within 5 business days, records the nature of the defect and raises a defect 'flag' noting the presence of a site defect in market settlement and transfer solutions (MSATS).
    - Within five business days of being notified of a site defect, the retailer sends a notice to the customer informing them of the need for remediation and requesting the customer to remediate in preparation for a smart meter installation. The retailer records the date of issue of the notice in MSATS. The notice would ideally outline any schemes or funding arrangements available to the customer for undertaking remediation work if available. The existing NER provisions providing exemptions from deployment timeframes would apply to the applicable types of deployments.
2. **If the retailer has not received confirmation from the customer that the site defect has been rectified within 2 months of issuing the first notice:**
    - The retailer is required to send a follow-up notice to the customer within one month of the two-month time period elapsing.
3. **The retailer confirms with the customer whether the site defect has been rectified within 2 months of issuing the second notice:**
    - The retailer is required to confirm the status of remediation with the customer, record the status of site remediation (successful or unsuccessful) in MSATS and report their success in undertaking the meter replacement in the retailer's next AER quarterly performance report.
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 relevant timeline requirements corresponding to the type of meter deployment in the NER. The Commission considers requiring retailers to follow the relevant timeline for meter replacements under the NER would be appropriate. The rules already contemplate the appropriate timeline arrangements for different types of deployment. This approach would enable consistency and simplicity of requirements.

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 (ie, a defect flag)
- the date of issue of the defect notice(s).

Retailers would record the above information in a database shared across retailers and metering coordinators such as MSATS.

Where a customer changes their retailer part-way through the notification process, the incoming retailer would be required to complete the remaining steps of the 2-stage notification process. For example, if a customer has already received one notice from their previous retailer, then the incoming retailer only needs to perform steps 2 to 4 above. This approach would reduce the regulatory burden on retailers and support better customer experience.

In circumstances where the customer at the NMI or the premises has changed part-way through the notification process, the retailer would be required to restart the two-stage notification process. This would enable the new customer to have ample opportunity to undertake remediation. The notification process would not need to be redone if there is a new customer at the NMI following the completion of a full notification cycle.

**The Commission has refined the process outlined in the draft report based on stakeholder feedback**

The process has been adjusted in light of the feedback from stakeholders. Key adjustments include:

- refinements to the information to be recorded. The Commission understands that changes to market systems such as MSATS will be needed to keep a record of the suggested information. The Commission considers that only necessary information should be recorded to minimise changes to market systems.
- requirements for retailers to check the status with the customer after the second notice. This will provide more certainty regarding the defect status of the site before the conclusion of the process.
- there would not be an explicit exemption from acceleration timelines for installing meters for site defects in the framework. The retailers would be required to report on and explain their performance as part of the performance requirements. The existing timeline exemptions in the framework for other types of deployments would continue to apply.[211]
- recording the defect information at the beginning of the process. This will help manage the issue of customer or retailer churn part-way through the notification process.
- clarifying that the performance reporting requirements related to site defects would be a separate obligation from the performance reporting requirements for acceleration. The reporting for defects would be an ongoing obligation whereas the reporting for acceleration would be time limited.

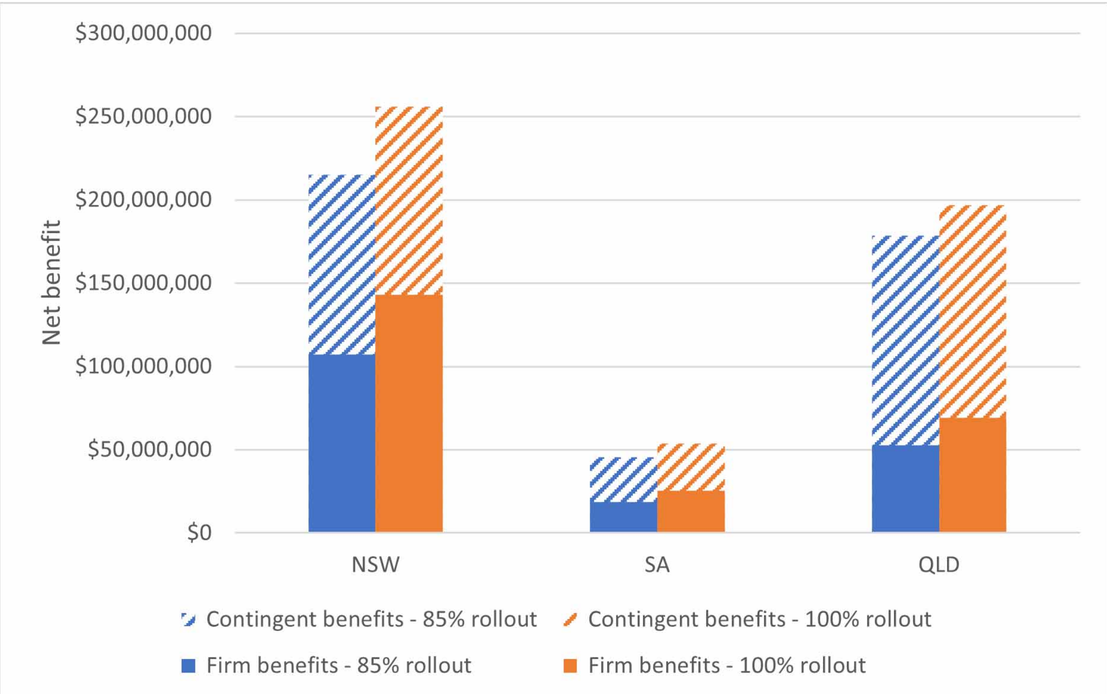
**A more widespread deployment is expected to have higher net-benefits**

211 [1] Clause 7.8.10, 7.8.10A, 7.8.10B, 7.8.10C of the NER.

We used the CBA results developed by Oakley Greenwood to assess the impacts of site defects limiting the level of smart meter penetration that could be achieved. The results of the impacts on the net-benefits of the deployment are shown in Figure D.2. It indicates that limiting the accelerated deployment to 85 per cent (that is, 85 per cent of the installations attempted during the accelerated deployment are successful) instead of reaching 100 per cent take-up leads to some loss of net benefits in all states. The net benefit is lower in New South Wales by $41 million (16 per cent), in South Australia by $8 million (15 per cent), and in Queensland by $18 million (9 per cent). If contingent benefits (related to tariff impacts and quicker restoration) are omitted, the limited deployment also leads to a decrease in the remaining 'firm' benefits. The loss of net benefits when considering only firm benefits is $36 million (25 per cent) in NSW, $7 million (27 per cent) in South Australia, and $16 million (24 per cent) in Queensland.

These results indicate that there would be a significant loss of net benefits due to site defects limiting the levels of smart meter penetration that can be reached. It should be noted that these results do not consider the efficiency loss of wasted site visits due to site defects and other benefits not quantified in the CBA such as loss of neutral detection. In addition to the net-benefit impacts, the Commission's view is that defects could lead to an inequitable deployment as explained below.

**Figure D.2: Acceleration has lower net benefits if it only reaches 85% of meters**




AEMC analysis based on Oakley Greenwood data.

Note: In this chart, the orange bars represent the core CBA results published with the draft report. The blue bars represent an alternate set of results where an accelerated rollout reaching 85 per cent is compared to a base case also reaching 85 per cent. Here, 85 per cent means that 85 per cent of legacy meters remaining at the start of the acceleration period (2025) are replaced, which yields an overall smart meter penetration of around 91 per cent.

### Vulnerable customers face greater risks of missing out

Vulnerable customers would face higher risks of being excluded from smart meter deployments due to remediation issues. This is because they are more likely to be in positions where decisions regarding remediation are out of their control, and they likely face higher financial hurdles for undertaking remediation, which tend to involve upfront costs.

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 authority to make decisions regarding remediation. Electrical installations generally form part of the infrastructure that the building owner or operator is required to provide and maintain.

This would leave vulnerable customers in a position where they are 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. As found by SEC Newgate Research, vulnerable customers, in particular, highly value the increased planning and budgeting abilities enabled by smart meters, including improved access to usage data and more frequent billing options.[212]

### Governments could consider levelling the playing field for customers

Jurisdictional governments could implement arrangements to help support customers to meet remediation costs, particularly vulnerable customers and their landlords. Governments could provide support so that vulnerable consumers are not excluded from the benefits of the smart meter deployment. Governments currently play an important and active role in levelling the playing field for customers, through arrangements that aim to deliver broader policy objectives, including promoting equity among energy consumers and policies aimed at energy affordability and emissions reduction. Concessions and rebates are often provided to customers:

- holding eligible concessions cards such as pensioner or health care cards
- on life support
- with medical conditions.

Concessions and rebates may be directly related to energy bills or may be targeted at reducing energy consumption by supporting initiatives such as installation of energy efficient equipment and appliances, better home insulation, or installation of consumer energy resources. Jurisdictions could develop similar schemes to support customers undertaking site remediation, to enable more widespread and equitable deployment of smart meters.

### Jurisdictions could review their remediation requirements when a smart meter is installed, to reduce the cost burden on consumers

212 SEC Newgate Research, *AEMC Metering Review - An assessment of consumer experiences relating to smart electricity meters and their competitive roll out within the National Electricity Market*, final report, p. 43.

The Commission understands that jurisdictional legislation and statutory instruments, such as Service Installation Rules (SIRs), outline what must be done when a smart meter is installed. Jurisdictions could review these instruments, to identify areas where remediation requirements could be safely reduced. Feedback received from metering parties highlighted that jurisdictional requirements were driving greater levels of site remediation, leading to additional remediation costs. Metering stakeholders also provided suggestions for adjustments to requirements that could safely improve the efficiency of the deployment. We understand that in some cases, the need for remediation is driven by the physical meter installation itself. For example:

- the new meter may be bigger, and may not fit where the old meter was located
- switchboard wiring and accessories such as links may be old and may break or lose insulation due to handling during the meter installation process, even though they were intact and safe prior.

In other cases, there are existing safety issues that need to be dealt with. While these issues may have nothing to do with the meter installation itself, the meter installer cannot ignore them. Although these are not directly related to the meter rollout, they may be related to a defect that needs to be dealt with prior to installation. Examples include:

- the presence of friable asbestos
- existing improperly installed or inadequate wiring and equipment
- lack of earthing
- insulation degradation due to age or heat
- high resistance connections.

In other cases, a meter installation triggers a need to undertake work in order to bring the switchboard in line with current standards, even though the existing installation is not unsafe. For example, we understand that in New South Wales, the replacement of a network meter with a smart meter is defined as an 'alteration' in the Service and Installation Rules, rather than a 'repair' or like-for-like replacement, even where the old meter is retired. This leads to several additional obligations including, for example, ensuring the multiple earthed neutral (MEN) connection is at the customer's main neutral link and not at the service neutral link, and upgrading the Metering Protective Device.[213] We understand that, as a result, the majority of sites in New South Wales require at least some remediation when a smart meter is installed. We understand that requirements are also inconsistent across jurisdictions. For example, in some jurisdictions, switchboards containing bonded asbestos can be worked on provided safe working methods are adopted, whereas in other jurisdictions bonded asbestos must be removed when particular work is undertaken. The Commission has benefited from the input of metering coordinators who provided significant and helpful information and analysis of areas where changes and standardisation could potentially assist in reducing costs and improving outcomes. We have not reproduced this information in this report as amendments to jurisdictional instruments are a matter for them. However, we understand metering coordinators may be willing to share this information directly with jurisdictions. We

213 New South Wales Service and Installation Rules, clause 1.12.11.

recommend that jurisdictions examine remediation obligations during the period of the Commission's subsequent rule change process, with a view to safely minimising the cost burden on consumers.

**Jurisdictions could also consider reviewing isolation requirements**

One meter coordinator also noted potential inefficiencies associated with live isolation in situations where service or meter protection devices, which would normally be used for isolation, are missing or not able to be operated. The meter coordinator believes that safe work procedures for live isolation of meters and fuse carriers at the switchboard are available, and that the current alternative of isolating supply from the network, sometimes involving live work at heights, was less safe and less efficient.

**Customers to retain responsibility for remediating sites**

Across the different stages of the Review, the Commission received suggestions for transferring the responsibility for remediation to the DNSPs. However, as previously noted, remediation work is undertaken on the customer's installation, which does not form part of the DNSP's network. Imposing a requirement on DNSPs to remediate customer sites would likely be outside the scope of the Commission's rule-making powers.[214] Reforms to jurisdictional arrangements would be needed to prescribe a remediation provider.

The Commission could make rules that require disconnection of sites where retired legacy meters are not replaced, due to a lack of remediation or otherwise, but we view that as a disproportionate response where the legacy meter has not reached the end of life. It would particularly impact vulnerable consumers and is likely to undermine social licence for the deployment.

The Commission has not formed a view on a preferred model for how remediation services are provided to customers should jurisdictions or the Commonwealth make arrangements to contribute towards remediation costs.

**Providing rights for metering parties to undertake some remedial work could enhance the deployment success**

Customer consent is generally required for remediation that is undertaken on the customer's installation rather than on network or retailer controlled equipment.

The Commission understands that, in order to complete jobs within a single visit, it is common for meter providers to undertake minor remediation work while on site, at no direct cost to the customer. As most new smart meter installations are currently the result of a customer request (for CER installations or otherwise), consent is not problematic. However, this may not be the case where smart meter installations are not customer initiated.

This raises two potential issues. Firstly, customers who have not asked for their meters to be replaced are unlikely to be motivated to provide consent in a timely manner. Secondly, the meter provider doesn't have a direct relationship with the customer. The customer's relationship is through the retailer, potentially adding significant administrative complexity.

214 NEL, s.34.

Given that there is no harm and arguably some benefit to consumers if minor remediation is undertaken free of charge, the Commission recommends jurisdictions review their legislative arrangements and consider allowing metering parties the ability to undertake some remedial work on the customer's installation without requiring the customer's consent if there is no charge. This would reduce the risk of the deployment being hindered by the inability of metering providers to conduct minor repairs of the customers' installations necessary for deploying smart meters.

## D.4 Providing metering parties access to network master keys

### D.4.1 The Commission recommends that meter providers and/or meter coordinators be given controlled access to industry master keys for meter rooms

Access to metering installation master keys that DNSPs hold would reduce costs and increase the success rate for meter installations.

### D.4.2 Metering parties say they cannot access legacy meters in locations secured by DNSPs

From consultation, the Commission understands some DNSPs hold master keys that provide access to sites currently secured by a DNSP locking system. Industry master keys are held by DNSPs due to their long-held responsibility over accumulation (Type 6) and interval (Type 5) meters, and these keys provide their staff or contractors with access to meters that are otherwise in locked switch rooms, cupboards, or a secured metering premise.

Some metering parties said that in New South Wales they are unable to complete meter replacements where they need network master keys to access legacy meters, leading to increased costs, delays and poor customer outcomes.[215] The industry estimates that lack of access to a network master key accounts for between 2-12 per cent of unsuccessful meter replacements. In these cases, legacy meters are installed in secured locations (e.g. switchrooms or padlocked meter boxes).

The Commission understands that DNSPs are prevented from sharing their industry master keys with third parties, including metering parties under New South Wales legislation. Under Section 54 of the *New South Wales Electricity Supply Act*, DNSPs can only facilitate access for 'an authorised officer of a network operator'. The same act also provides retailers and their authorised officers, metering coordinators and meter providers powers of entry,[216] but the power is moot if they don't have access to the keys securing the metering locations.

Customers can access their legacy meters in these secured locations using their own bespoke key. However, metering parties note some customers are unaware of or have lost the key and cannot facilitate access. DNSPs and metering parties note these customers would need to acquire a new bespoke key, adding cost and inconvenience. Even if the key can be found, obtaining it from the customer or body corporate may involve locating and contacting the customer or body corporate officer and arranging to meet them at a mutually convenient time (possibly outside of normal working hours), adding time and cost.

215 Submission to the Consultation Paper, directions paper, p, 20; submission to the directions paper, Vector, p. 23; submission to the draft report, PLUS ES, p. 38.

216 New South Wales Electricity Supply Act 1995, Part 5, Division 3 and section 196.

Vector notes that some stakeholders have proposed a solution involving the metering industry introducing its own secure locking system. It raises concerns that this approach would involve customers incurring a significant cost, as it requires the replacement of a functioning locking system.[217] Further, DNSPs may continue to require access for isolation purposes, so it may not be possible to replace their locks.

A more efficient solution would be to remove the constraint on DNSPs issuing keys, and to require DNSPs to make keys available through a secure and managed process.

### D.4.3 DNSPs facilitating access to industry master keys for metering parties would support acceleration and mitigate costs to customers

The Commission considers that providing metering parties with the ability to access secured meter sites, such as by enabling them to use network master keys held by the DNSP, would help support the smart meter deployment. However, based on the above this would require a change to New South Wales jurisdictional legislation.

The Commission recognises that additional procedures and controls may need to be put in place so that DNSP key systems remain secure.

The Commission considers that legislative amendments to allow metering parties to gain appropriate access would:

- reduce wasted site visits and the costs of the smart meter deployment
- enable more customers to benefit from the smart meter deployment
- reduce delays in meter replacements and improve customer experience in the deployment (e.g. through tenants not needing to collect the bespoke key from the landlord/real estate agent or customer avoiding having to pay the cost of a new bespoke key).

## D.5 Removal of the option to disable remote communications

### D.5.1 The Commission recommends retaining the option to disable remote communications

The Commission's final recommendation is customers have the option to have the remote communication capabilities of smart meters disabled to accommodate their preferences and circumstances. For example, some customers in regional or rural regions may not have access to a reliable telecommunications network. Customers who prefer or choose to have remote communications disabled would receive a Type 4A meter instead of a Type 4 meter.

### D.5.2 Stakeholders had mixed views considering customer concerns and the benefits of smart meters

Under current arrangements, customers can choose to have remote communications disabled and request a Type 4A meter. In the draft report, the Commission initially considered this choice may lead to reduced benefits, inefficiencies and higher metering costs due to site visits for manual reading. Oakley Greenwood finds that avoiding having to manually read

217 Submission to directions paper, Vector, p. 23.

meters is a significant driver of the positive net benefit for all states from accelerated deployment.

Stakeholders present mixed views. Some Retailers, DNSPs and many metering parties think that the option to disable remote communications should be removed. They consider remote capabilities as a primary benefit of digital smart meters (e.g. remote reads, re-energisation and de-energisation) and that the provision of smart meters with disabled communications (Type 4A) creates additional costs.[218] Opposing stakeholders including consumer groups, a few metering parties and a retailer note there are some customers who strongly prefer to have remote communications disabled and/or lack reliable access to the telecommunications network to facilitate remote communications as they live in regional/rural areas.[219] They note preserving the option to disable communications would help promote social licence for smart meter deployments.

### D.5.3 Retaining the option to disable remote access may benefit some customers, and provide others with a greater degree of agency

The Commission considers that removing the option for remote communications to be disabled may lead to costs outweighing the benefits in some locations, as well as risking social licence of accelerated deployment. In addition, it found that:

- currently less than 0.01 per cent of customers opt for Type 4A meters, meaning the option is not expected to significantly impact the deployment benefits.
- retailers and metering parties have sufficient incentive to provide customers with Type 4, instead of Type 4A meters
- additional meter reading costs may exclusively be passed onto customers that opt for a Type 4A meter.

Retaining the option to disable remote communications is unlikely to diminish the benefits of the accelerated deployment. The option could also help promote the social licence of the deployment, especially considering the removal of provisions enabling customer opt-out.

## D.6 Improving industry coordination and minimising negative customer impacts in shared fusing scenarios

### D.6.1 The Commission recommends a ‘one-in-all-in’ approach for meter replacements at multi-occupancy sites

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

218 Submissions to the draft report: Alinta, p. 2, 6; Momentum Energy, p. 5; Origin, p. 4; Green Metering, p. 9; SNAPI, p. 3; SwitchDin, p. 7; Secure Meters, p. 6; EDMI, p. 10; SAPN, p. 8; CEC, p. 2; Telstra, p. 6.

219 Submissions to the draft report: AGL, p. 10; Vector, p. 8; PLUS ES, p. 12; PIAC, p. 16; SACOSS, p. 7; EWO, p. 5; ACOSS, p. 5; ETU, p. 10.

### D.6.2 Meter replacements for customer 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 can result in a negative customer experience. Shared fusing tends to be more prevalent in older electrical installations as jurisdictional regulations now require individual isolation of meters in new electrical installations. Vector indicated 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.[220] Gathered from submissions to the Consultation Paper and directions paper, the three main issues caused by shared fusing 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[221] made in 2019 partly resolved the issue, but the Commission considers a new process is required in an accelerated deployment.

### D.6.3 Stakeholders support one-in-all-in and propose refinements

Most stakeholders support the one-in-all-in mechanism proposed in the draft report, noting it would provide for more efficient and cost-effective installations and improve industry coordination.[222] Many stakeholders suggested changes to the draft process. Examples of suggested changes include:[223]

- DNSPs to play a more direct role in the process, such as acting as the MP
- nominating a single metering coordinator for a site with shared-fusing
- requiring DNSPs to notify the MP of planned interruptions
- enabling metering coordinators to have access to NMI discovery to enable coordination of meter replacements with other metering parties and retailers.

Stakeholder feedback received from submissions and consultation also provided suggestions for issues that needed further consideration, including whether:

- recovering the cost of Temporary Isolation of Group Supply (TIGS) from impacted retailers on a pro-rata basis is appropriate and fair.[224]

220 Vector submission to directions paper, p. 17.

221 AEMC, Introduction of metering coordinator planned interruptions, May 2020, https://www.aemc.gov.au/rulechanges/introduction-metering-coordinator-planned-interruptions.

222 Submissions to draft report: Alinta, p. 6; Aurora, p. 3; EnergyAustralia, p. 4; Evoenergy, p. 4; Momentum Energy, p. 2; AGL, p. 12; Actew AGL, p. 3; PLUS ES, p. 15; ECA, p. 8; Vector, p. 10; Secure Meters, p. 7; SwitchDin, p. 8; EWO, p. 6; ACOSS; p. 5; Ausgrid, p. 7; Endeavour, p. 1; TasNetworks, p. 3; SAPN, p. 8.

223 Submissions to the draft report: SAPN, pp. 2-3; PLUS ES, p. 18.

224 Submissions to draft report: Green Metering, p. 11; Alinta, pp. 6-7; SwitchDin, p. 8; Vector, p. 10; PLUS ES, pp. 15-17; TasNetworks, p. 3; SAPN, pp. 2-3, 9; Ausgrid, p 7, 8; ETU, p. 13; Alinta, p. 7; AGL, pp. 12, 14; Secure Meters, p. 7; Intellihub, p. 6.

- the existing TIGS process would allow TIGS costs to be recovered on a pro-rata basis but may require some process and system changes. For example, changes to the pricing approach, where DNSPs could possibly set multiple price tiers that depend on the number of meters involved in the TIGS.
- the DNSP is the most appropriate party to notify customers of planned interruptions to supply under one-in-all-in. Some stakeholders highlighted that DNSPs are responsible for scheduling and managing the interruption and have visibility of impacted customers retailers and customers, including life support customers.
- the proposed timeframes are reasonable.
- affected parties may need flexibility or leniency from timeframe obligations in order to accommodate for circumstances that are unforeseen or outside of the party's control (e.g. agreeing on an outage date with customer(s) outside of the obligation timeframes, coordination issues or where there is a site defect.)
- there should be a cap of up to 10 meters for every interruption under the one-in-all-in approach

Some stakeholders are not in favour of the approach:[225]

- PIAC think issues associated with shared-fusing would not exist if DNSPs were able to appoint metering coordinators directly.[226]
- AEMO considers that parties should be able to coordinate via commercial arrangements without regulation.[227]

### D.6.4 A one-in-all-in approach will better support meter replacements in shared-fusing scenarios

The 'one-in-all-in' approach seeks to improve coordination, provide guidance and clarify 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
- 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 and enabling scale efficiencies.

225 Submissions to draft report: Origin, p. 6; AEMO, p. 9; PIAC, pp. 18-19; Telstra, p. 8.

226 PIAC submission to draft report, pp. 18-19.

227 AEMO submission to draft report, p. 9.

- 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.

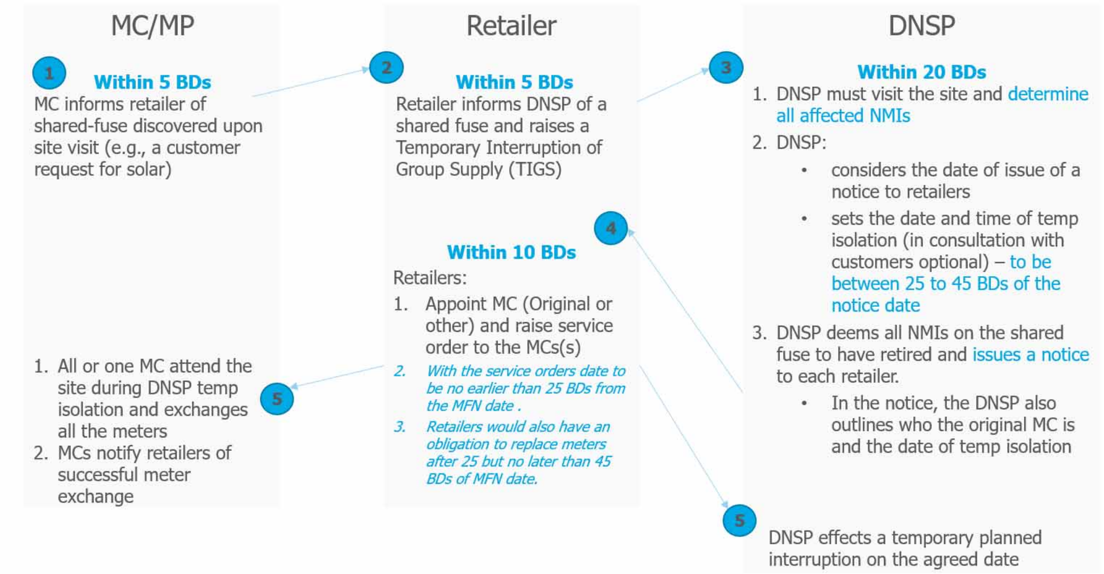
The following section outlines the details of the proposed approach.

### D.6.5 The multi-occupancy scenario — key steps of one-in-all-in

The one-in-all-in approach under the multi-occupancy scenario would be applicable to sites where replacements of legacy meters aren't prevented from going ahead due to site defects (e.g., asbestos, meter board upgrades required and wiring issues). As an ongoing provision, it could be triggered under any type of deployment, e.g. customer requests, malfunctions or acceleration. The same obligations and timelines would apply regardless of the type of deployment that triggered the one-in-all-in process.

Figure D.3 below shows a step-by-step process of the proposed multi-occupancy scenario. Figure D.4 outlines the timeframes.

**Figure D.3: Step-by-step process of a multi-occupation scenario**



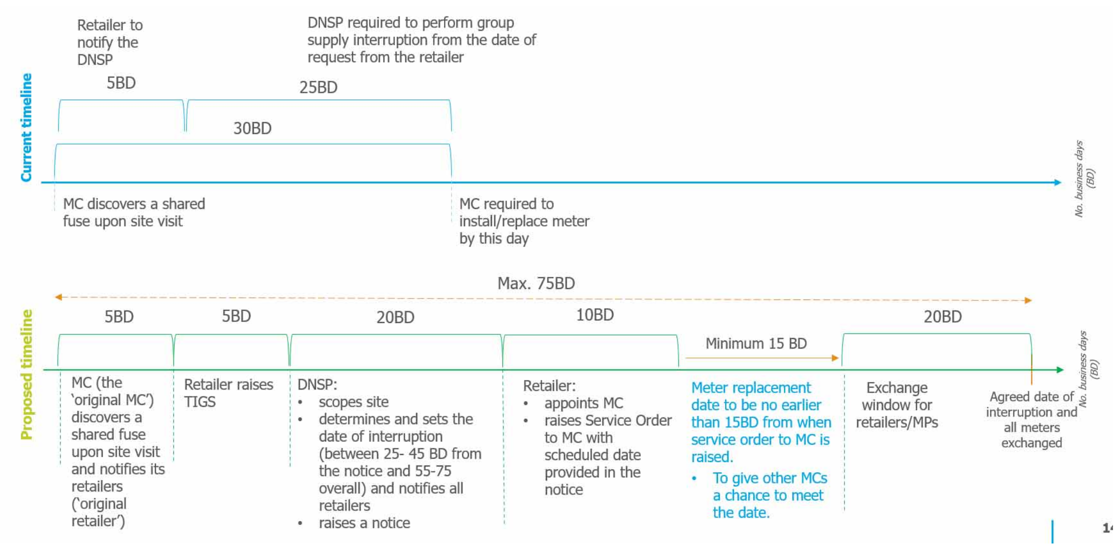

AEMC

Where applicable, the one-in-all-in process under the multi-occupancy 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 metering coordinator must inform the retailer, who originally authorised the MP's visit to the site, within five business days 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 metering provider' or 'primary metering coordinator' 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:
  - visit the site and determine all affected NMIs on the shared fuse
  - set a date and time for a TIGS. In setting the duration of the outage, the DNSP should consider the length of time reasonably required to undertake the required upgrades.
  - deem all the legacy meters (NMIs) on the shared fuse to be no longer fit for purpose and issue a notification to the retailers of the respective NMIs. A notification similar to the existing Meter Fault and Issue Notification (MFIN) could be developed if necessary and used to notify all retailers. The notification should outline details of the primary metering coordinator and the date and time of the scheduled temporary isolation. The date must be between 25 and 45 business days after the notice has been issued. This provides at least 20 business days for the primary metering coodinator(s) to plan and schedule meter replacement(s). The information in the notice should enable retailers to appoint the primary metering coordinator as their metering coordinator 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 metering coordinators:** Within 10 business days of receiving a notification from the DNSP, the retailers will be required to appoint a metering coordinator (the primary metering coordinator or one of their choosing) and raise a Service Order for meter replacement(s). The Commission considers that providing at least 15 business days would allow metering parties to align the received Service Order 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:** the DNSP undertakes 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.

## Figure D.4: Timeline for one-in-all-in approach




AEMC

## D.6.6 Key considerations for implementing one-in-all-in

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. The sections below outline further details relating to how the process would work in practice.

### Appointment of metering coordinator(s)

Under the proposed 'one-in-all-in' approach, retailers can either appoint the Primary metering coordinator or a metering coordinator of their choice. If all or most retailers on the shared-fuse site appoint a single metering coordinator (i.e., the Primary metering coordinator), the installation efficiencies could be significantly enhanced — the communication, coordination, and the installation process would be more streamlined and cost-effective.

Should retailers choose to appoint a different metering coordinator, the Commission expects they would schedule meter upgrades to take place during the planned interruption window outlined in the DNSP's notice. As explained below, the approach to recovering temporary isolation costs should incentivise retailers to minimise interruptions. This should enable meter replacements with fewer outages.

The Commission considers that DNSPs are the appropriate party to notify customers of planned interruptions. This is consistent with the current arrangement where if a DNSP is carrying out a distributor-planned interruption for a number of affected customers on a shared fuse to replace any meters, then the retailer shouldn't send their customers a planned interruption notice as well.[228]

### One-in-all-in approach would not apply to sites requiring remediation

Prior to triggering the one-in-all-in process, metering coordinators should consider whether meters for all customers on the metering board can be upgraded without needing significant remedial work. Where site defects are found, the one-in-all-in process shouldn't be triggered and the customer will need to remediate the defects before the upgrade can progress. The proposed site defect tracking and notification process (see appendix D.3.4 for details) for site defects will apply. Where a customer has undertaken remediation, the one-in-all-in process may no longer be required, because remediation can often resolve shared-fusing issues.

### How the one-in-all-in approach fits with acceleration timelines

Retailers and metering coordinators will have 12 months to replace a batch of NMIs under the LMRP acceleration mechanism. The retirement of NMIs is expected to take place on a geographic basis. This means that NMIs on shared fused should be retired and scheduled for replacement in the same year. Where a retired NMI is visited by an MP triggering the one-in-all-in process, the above-mentioned process and a 75-business day timeframe will apply. This means a site that was originally in the LMRP could face replacement timeframes shorter or longer than the 1-year depending on when in the LMRP replacement cycle, the one-in-all-process was triggered.

### Payment and allocation of TIGS

The Commission considers that the TIGS cost should be recovered from all relevant retailers on the shared fuse on a pro-rata basis when the one-in-all-in approach is used. This approach would strengthen the effectiveness of the mechanism as it incentivises all retailers with legacy meter customers on a shared-fuse to coordinate meter replacements to take place at the same time (i.e. in line with the scheduled temporary isolation) and reduce the number of outages faced by customers. Retailers who do not organise a meter replacement during the DNSP scheduled temporary isolation would need to raise a separate temporary isolation request to the DNSP. This would attract isolation costs additional to the pro-rated TIGS costs to be paid by all retailers on the shared fuse.

The AER may have sufficient flexibility under the NER to give effect to the cost recovery of TIGS on a pro-rata basis.[229]If further clarity in the rules would benefit the implementation of the proposed cost recovery approach, then the relevant changes can be considered in the potential subsequent rule change process.

### Circumstances under which the one-in-all-in approach apply

The Commission considered whether the one-in-all-in process should only apply when the number of NMIs on a shared fuse is within a set range.  A few metering parties provided

228 See Rule 59B of the NERR.

229 For example, through regulatory determinations.

support in consultation, noting that it is believed most multi-occupancy sites with shared fusing would have 10 or fewer meters on a single fuse or main switch.

The Commission views a prescribed numeric range for the number of NMIs as not necessary and recommends market participants take a principled approach. The one-in-all-in approach should be used in circumstances and in a manner that would help minimise the number and length of supply interruptions to all customers on a shared fuse and promote efficient meter deployments. For example, it may be more efficient to use the current business approach instead of the one-in-all-in for duplexes with two NMIs. A more principled approach would help overcome the risks of setting a one-size fits all approach and allow the metering parties to take into account site-specific circumstances.

**Metering coordinator access to NMI Discovery in MSATS**

Vector and other metering parties proposed that they should have access to NMI Standing Data that relates to NMIs that they have not been appointed to for operational efficiency reasons,  and to support industry coordination of meter upgrades and replacements. For example, this would allow, metering coordinators to be able to coordinate meter replacements with other metering parties that retailers have appointed for NMIs on a shared fuse.[230] Both metering coordinators and AEMO note rule 7.15 of the NER poses a barrier to allowing metering coordinators access to NMI Discovery. The Commission views this as an issue that should be considered further during the rule change process, in the context of the one-in-all-in approach and potentially other circumstances where metering coordinators require access to NMI Discovery when undertaking meter upgrades or replacements.

**Flexibility in timeframe obligations**

Some stakeholders consider that flexibility on timeframe obligations may be required. For example, DNSPs may need more than the proposed 20 business days to consult with customers on a shared fuse about the date and time of a planned interruption. It would also be challenging to obtain agreement from multiple impacted customers.[231]

The Commission notes that the current arrangements for planned interruptions will apply under the one-in-all-in approach. Therefore, DNSPs will not need to obtain affected customers' consent to a planned interruption, but they will need to notify customers of the date of interruption at least 4 business days prior to the interruption. See rule 90 of the NERR.

The one-in-all-in process depends on different parties undertaking activities concurrently and in a coordinated fashion. The provision of extensions to the timeframe of the one-in-all-in process would impact other parties in the remainder of the process in a way that could add additional costs (e.g. operational costs for re-scheduling) and cause delays to meter replacements. For these reasons the Commission doesn't support additional flexibility.

For the implementation of the proposed one-in-all-in process, please see drafting instruction number 6 in table I.1.

230 Vector, submission to draft report, p. 10.

231 Submissions to draft report: SAPN, pp. 2,3,8,9; ETU, p. 13; Alinta, pp. 6-7; AGL, p. 12.

### D.6.7 Alternative approaches for addressing shared-fusing issues at multi-occupancy sites 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.

# E ENABLING BETTER ACCESS TO POWER QUALITY DATA

This appendix outlines the Commission's final recommendation for improved access and sharing of power quality data (PQD) that smart meters can provide.

The Commission considers that access to information about the customer's electrical power supply will be increasingly crucial for the future distribution system's operation. Better access to PQD should contribute to DNSP's understanding of the network, paving the way for DNSPs to deliver several beneficial outcomes: saving energy by reducing line losses, minimising safety risks, maximising hosting capacity and driving down costs within the distribution network by extracting the most value from the existing distribution network assets and optimising future investment decisions.

Stakeholder feedback and the Commission's previous analysis have identified several opportunities to promote better outcomes for consumers and the broader market, including:

- Improving standardisation in the data structure, types, sequencing, and frequency of data provided across participants.
- Reducing differences in exchange architectures or methods for PQD access.
- Addressing a potential lack of competition where data is required from a high percentage of sites.

To promote better outcomes for consumers and the broader market, we have identified specific areas for improvement — focusing on standardisation, and defining responsibilities (see Recommendation 4). Ensuring continuous access to basic types of PQD is essential for identifying power quality issues and implementing mitigation measures.

### RECOMMENDATION 4: ENABLE BETTER POWER QUALITY DATA ACCESS

1. Define what power quality data is in National Electricity Rules (see appendix E.1).
2. Define what the 'basic' power quality data service includes (see Box 2):
   a. **Data type:** Voltage, current, and phase angle, including relevant National Meter Identifier Standing Data.
   b. **Data forma**t: Recorded for every trading interval, element, and phase.
   c. **Data frequency**: at the batching and provision at least once per day to the local distribution network service provider.
   d. **Exceptions:** Where metering installations do not have sufficient communications infrastructure, for example.
3. Require that metering coordinators ensure that 'basic' power quality data is capable of being collected, processed, and delivered.
4. Require the metering data provider to share 'basic' power quality data with the local distribution network service provider.

5. Enable the Australian Energy Market Operator procedures to determine the exchange of 'basic' power quality data and metering data performance standards, or service-level procedures, for 'basic' power quality data (see appendix E.2).
6. Enable the local distribution network service provider to receive 'basic' power quality data free of direct charge, without undue delay, and continuously, where applicable (see appendix E.3).

## E.1 'Basic' power quality data should be standardised in the NER

Our final recommendation is to define PQD in the NER , define what the 'basic' type of data is, and require its provision to the local DNSP regularly. Implementing this recommendation requires changes to the NER to define 'basic' PQD and the standardisation that metering service providers must follow (see Box 2). An MC would be necessary to ensure that the smart meter installation is capable of collecting, processing, retaining, and delivering "power quality data" under NER 7.6.1 – whereas the MDP would be responsible for providing 'basic' PQD to the local DNSP, free of direct charge, without undue delay and where applicable continuously.

### BOX 2: WHAT IS 'BASIC' POWER QUALITY DATA?

We recommend defining the basic level of PQD to include:

- Voltage, current, and power factor (which is active and reactive power and could be represented as a phase angle).
- Data points recorded for every trading interval, element, and phase.
- Batching and provision at least once per day to the local DNSP (see section next).
- Relevant NMI Standing Data.

For the avoidance of doubt, we recommend that metering service providers do not need to collect, process, retain, or deliver 'basic' PQD where:

- The customer in respect of a metering installation is a large customer, or the metering installation is located on or at a transmission network connection point.
- The metering installation is a type 4 meter and was installed before the implementation of Power of Choice on 1 December 2017.
- The metering installation is a type 4A meter incapable of remote communications. This exemption will no longer apply if the meter ceases to be a type 4A meter.

Our final recommendation is consistent with our draft recommendation. Stakeholder submissions to the Draft report support this approach, as it:[232]

- **Aligns with existing requirements**: Metering service providers must maintain standards for collecting, processing, and delivering data per the NER, procedures, and their pattern approvals. Our recommendations for 'basic' PQD should align with those requirements.
- **Considers roles and responsibilities**: Vector and PLUS ES suggested that the MP or MDP role may be more appropriate than the MC role to provide PQD, consistent with our final recommendation. This is due to the differences in practice from regulation and operational challenges like churn.
- **Includes endorsement of the working group's findings**: The final recommendation has been guided by the recommendations of the working group and it has broad support from other stakeholders, including the use of JavaScript Object Notation formatting language
- **Introduces an adaptable and relevant definition**: We have recommended flexible and future proof definitions be incorporated in the NER to accommodate changing industry contexts and technology trends**.**
- **Keeps the definition targeted**: Voltage, current, and power factor are necessary and sufficient for 'basic' PQD. Additionally, we recommend that relevant NMI standing data should be provided. Stakeholders recognise there are other variables and forms of information. These could be included in more 'advanced' PQD services.

### E.1.1 'Basic' power quality data should be delivered at least once a day

Our final recommendation is that 'basic' PQD should be delivered at least once a day, as this is sufficient for most DNSP use cases. Increasing the frequency of data received is not expected to deliver incremental value, except where real-time operations and controls are necessary; which we recommend could be considered an 'advanced' service (see appendix E.4).

The Draft report indicated a need to explore the significant cost difference between daily and 6-hourly data delivery frequencies, based on the working group's preferences for more frequent data. Stakeholder's submissions consistently highlighted that once a day is most likely sufficient: pulling 288 intervals of 'basic' PQD from the smart meter and delivering that to the local DNSP once daily satisfies most use cases.[233] The existing use cases for 'basic' PQD are outlined in Table E.1 below.  The Commission expects new use cases to emerge with greater CER and storage penetration, including increased roadside vehicle charging.

The AEMC hosted an industry working group on 'basic' PQD after the Draft report that further considered the issue to inform our final recommendation. DNSPs and MCs further evaluated

232 Submissions to the Draft report: Ausgrid, p. 10; CEC, p. 4; ENA, p. 4; Endeavour Energy, p. 5; Energy Queensland, p. 29; ETU, p. 16; Evoenergy, p. 5; Green Metering, p. 16; Intellihub, p. 9; Origin, p. 8; PIAC, p. 28; PLUS ES, p. 25; Secure Meters, p. 9; SA Power Networks, p. 11; SwitchDin, p. 10; Vector, p. 13.

233 Submissions to the Draft report: CEC, p. 4; Energy Queensland, p. 29; ETU, p. 16; Evoenergy, p. 5; Intellihub, p. 9; Origin, p. 8; PLUS ES, pp. 25-26; SA Power Networks, p. 12; SwitchDin, p. 10.

the costs and benefits of the potential options. Metering service providers indicated that the additional costs of batching and delivering 72 data intervals four times a day (i.e. 6 hourly) would be more expensive than once daily due to the need to establish multiple conversations with the smart meter outside of its usual timeframes. We did not identify any use cases that materially benefit from a 6-hourly delivery compared to a daily delivery frequency — except where value could be derived from 'advanced' services — which was validated by the working group.

## E.2 'Basic' power quality data should be exchanged in a standard consistent way with appropriate service levels

We recommend establishing a standard and consistent exchange architecture for 'basic' PQD with appropriate service levels. This will ensure a more efficient and uniform data access approach in the metering services regulatory framework. While our final recommendation is for the NER to enable these outcomes, the specific details should be finalised in AEMO procedures, allowing for flexibility in implementation.

Another component of our final recommendation is for 'basic' PQD to be provided at no direct cost (see appendix E.3). This removes the parties' ability to agree on definitions, service levels and exchange methods through commercial negotiation necessitating the regulatory framework establishing a standard and consistent exchange method, with appropriate service levels consistent across metering service providers and local network areas.

### E.2.1 Our recommendation is different from the Draft report but builds on stakeholder engagement

Our Draft report recommended that 'basic' PQD be commercially determined so that participants could each receive their desired exchange method and service levels.[234] By default, two parties could exchange data directly from peer to peer while leveraging the shared market protocol.[235] Stakeholders did support this exchange method and indicated that:[236]

- **'Basic' PQD needs a standard interface**: All parties using the same exchange architecture for 'basic' PQD should contribute to the potential benefits of access.
- **Leverage existing arrangements**: Existing transactions and protocols should be adopted to minimise duplication of costs and effort.
- **Need for service-level agreements**: While it would be preferable to leave service levels to agreements between two parties to determine what best suits their

234 Service level agreements that were intended to be negotiated and inform how parties would agree to include success rates, data integrity, retention, and downtime.

235 The peer-to-peer exchange was introduced in 2017 by Power of Choice. The transaction group 'PTPE' allows for exchanging information and/or attachments between participants. While it operates via aseXML, it includes an <FreeFormData> element that supports any text-based data exchange, such as JSON or CSV, given there's a bilateral agreement on the data structure. Peer-to-peer exchange is detailed in the SMP technical guide but not in any AEMO Procedural documents to support off-market data exchanges based on bilateral agreements. It does have a one-megabyte message size limit for file transfer protocol exchanges and two-megabyte limit for application programming interface exchanges. There is no character limit, but eventually, a peer-to-peer transaction would exceed the maximum message size.

236 Submissions to the Draft report: Energy Queensland, pp 29-30; ETU, p. 16; Evoenergy, p. 5; Green Metering, p. 16; Intellihub, p. 9; PLUS ES, p. 26; SA Power Networks, pp 12-13; Secure Meters, p. 10; Vector, p. 13.

circumstances, there is a stronger impetus to create a uniform service level for 'basic' PQD.

- **Peer-to-peer transactions are sufficient**: Despite the potential benefits of a centralised data hub approach, there is likely marginal incremental cost to retaining a peer-to-peer arrangement – provided that everything else is standardised.

The AEMC hosted an industry working group on 'basic' PQD after the Draft report that met to develop an industry-agreed approach to exchange architecture and service levels for 'basic' PQD; however, participants could not agree on the exact settings. Practically, this meant industry participants could not agree on using current NER clause 7.17.1 (f) to agree to share the data directly from peer-to-peer.

Working group participants advocated against hard coding service levels for 'basic' PQD in the NER because of potential risks of redundancy over time and for MCs in trying to meet a too high a standard (like settlements-ready data) while scaling their systems. The group preferred setting service levels through a subsidiary instrument like AEMO's Procedures because, without clear governance, potential dysfunction could eventuate and undermine the benefits of industry standardisation.

### E.2.2 AEMO should determine the default exchange method and service levels

The Commission considers there is a need to determine the appropriate service level agreements for basic PQD. Their development would be appropriately progressed in concurrence with the transaction for exchanging basic PQD.

We recommend that AEMO align the delivery, operation and conformance management of a 'basic' PQD requirement to that of the existing metering data delivery service, leveraging the existing framework. This would necessitate changes in the service level procedures for MDP services, and potentially other changes to other procedures like the B2B. We recommend that AEMO consider the findings of this review, including the following principles that were co-designed by 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. Focus on core use cases to encourage uptake that will create value across the Australian electricity sector.
- Leverage existing business-to-business standards and patterns as described in the shared market protocol and 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.

Currently, AEMO must establish, maintain and publish the service level procedures that will apply to MDPs. Current NER clause 7.16.7 allows AEMO to amend those procedures in accordance with the Rules consultation procedures — especially to determine ongoing and future compliance. Consultation should be key to balancing the interests of affected stakeholders with the general objective of facilitating 'basic' PQD sharing.

We understand that service-level obligations were intentionally removed from the B2B arrangements to make them more outcomes-focused. The communication transaction's outcome determines the service level, i.e. how long it takes to deliver a payload from Party A to Party B is the delivery time.

Participants could utilise existing B2B transactions for 'basic' PQD sharing, or in the case that none are deemed suitable, propose an amendment or addition to the B2B procedures for the consideration of the Information Exchange Committee.

## E.3 'Basic' power quality data should be provided free of direct charge

The Commission's final recommendation is that 'basic' PQD service should be provided to the local DNSP free of direct charge. This differs from our draft recommendation on 'basic' PQD cost allocation. In coming to our final recommendation, the Commission performed a multi-criteria analysis to compare three options:

1. A commercial model similar to the draft recommendation, with improved terms and conditions. This option aimed to ensure procurement of only necessary data at a negotiated price, with improvements in long-term contracts and service levels. It also included a neutral integrity service to detect faults in smart meters – preserving an effective level of choice. Contracts would have lighter ex post compliance and enforcement clauses, with recourse available through mediation or arbitration in case of breaches.
2. The final recommendation, whereby MCs provide 'basic' PQD part of their core service. The cost would be incorporated into their competitive offers to retailers.
3. A regulated price was considered possible, but ultimately the Commission considered it was infeasible because it incur unnecessary administrative costs, and would likely be an inferior substitute for competitive costs determined as part of the core service pricing to retailers.  In both cases, the costs are ultimately passed on to consumers.

We assessed each option against five decision-making assessment criteria, ranking their performance. Option 2 emerged as the preferred choice based on these evaluations.

- **Effective level of choice**: Engagement with DNSPs has revealed that some 'basic' PQD use cases require access to data that leaves them as price takers. In the below situations, DNSPs could have limited bargaining power in negotiating efficient prices for 'basic' PQD. This would result in higher costs for data access than necessary which would be passed on to consumers. DNSPs would require access to 'basic' PQD because:

    - Neutral integrity issues can't be detected by meters outside a customer's individual premises. To monitor neutral integrity, data is needed from all premises. Likewise, CER compliance with technical standards can only be determined at the premises level.
    - Some other use cases also require data from a significant proportion of meters to deliver optimal customer benefits, meaning that in some cases, data may be required from all major MCs.
- **Expected competition effects**: Management of these new costs could be better determined competitively, through the annualised and long-term contracts between retailers and MCs. The intended competitive pressure between retailers and MCs could better reveal efficient costs over time. The net effect would be a more efficient distribution of costs that aligns with the current framework's commercial incentives.
- **Alternative measures would build in complexity**: DNSPs' concerns around the high price of access under commercial arrangements could potentially be dealt with through several options: facilitating long-term contracts, carving out neutral integrity and other services, regulating a fair, reasonable, and non-discriminatory access price, or negotiate-arbitrate obligations. However, the implementation of these measures would not justify the intended solution. This final recommendation is more straightforward.
- **Improved certainty of access and consumer benefits:** Unlike the draft recommendation, this final recommendation would avoid scenarios where DNSPs fail to gain access due to failure to negotiate a favourable price — meaning consumers could miss out on material benefits. Requiring that 'basic' PQD is provided free of direct charge would ensure that all DNSPs receive it with certainty. DNSPs could invest in infrastructure, processes, and capabilities to use and apply 'basic' PQD. Consumers would be able to receive benefits that are not dependent on whether the DNSP was able to negotiate favourable prices or pay for access.
- **Potential for more significant long-term benefits**: Zero-cost DNSP access to 'basic' PQD would enable multiple other benefits, including further benefits and use cases that may arise in an evolving electricity system, like predictive maintenance and planning or improving the integration of CER. The expectation is that this would result in lower costs flowing through to customers, with more significant incentives for parties to reduce the costs of providing PQD compared to other options.

Stakeholder positions shifted in response to the Draft report recommendation that DNSPs should negotiate access to 'basic' PQD. Some stakeholders believe that a commercial model where the beneficiary pays is unworkable with a target deployment rate of 100 per cent – especially because of the potential for DNSPs to be price takers as described above. This could mean that DNSPs could incur higher average costs from MCs – meaning higher costs for consumers in turn.[237] Other stakeholders agreed with the Draft report, supporting a commercial model where the beneficiary pays due to its efficient allocation of costs.[238]

237 Submissions to the Draft report: ACOSS, p. 23; Ausgrid, p. 10; CEC, pp. 4-5; ENA, p. 4; Energy Queensland, pp. 28-29; Essential Energy, p. 13; Evoenergy, p. 6; PIAC, p. 25; SA Power Networks, pp. 15-16; Shane Rattenbury MLA, pp. 1-2; SwitchDin, p. 11; TasNetworks, p. 3.

238 Submissions to the Draft report: AGL, p. 17; Green Metering, p. 18; Intellihub, p. 7; Momentum, p. 7; Origin, p. 8; PLUS ES, p.

### E.3.1 Our final recommendation does have potential cost implications

The Commission understands the potential cost implications of the proposed access and cost recovery arrangements for 'basic' PQD. In 2021, we asked each major MC to provide confidential high-level cost estimates for 'basic' PQD. The data specification that MCs estimated was more extensive tthan the final recommendation. MCs were encouraged to provide per-unit fees and any fixed one-time costs. Each MC's per-unit and fixed cost estimates were within a reasonable range of the others.

We understand that the per meter per year costs of 'basic' PQD are likely to be modest – and an order of magnitude lower than the cost of providing real-time data. MC's would also incur one-time costs, which could be moderate, involve building communications channels and scaling data dispatch. DNSP's marginal cost of building, integrating, and operating systems to receive 'basic' PQD must be prudent and efficient.

We expect that an accelerated smart meter deployment (i.e. reaching a critical mass of smart meters sooner) would decrease the per-unit operating costs at a significant rate due to increased economies of scale and scope. 'Basic' PQD is a new additional obligation on metering service providers, which will involve some costs.

Costs could likely be lower than we expect for several reasons. The accelerated deployment of smart meters will not be 100 per cent successful, and some meter's remote communications will be disabled. Investment is already underway to provide this service under the current arrangements. Retailers should be able to negotiate a more efficient 'basic' PQD price commercially – reasonable costs amortised over the meter's life.

### E.3.2 Our final recommendation should also deliver benefits

The Commission also understands the potential benefits of the proposed access and cost recovery arrangements. Consistent and ongoing access to 'basic' PQD will enable several DNSP use cases necessary for efficiently operating the distribution system – which may not have reached the data penetration required for DNSPs to deliver optimal customer benefits (see Table E.1).

Table E.1: **DNSP use cases that are enabled by 'basic' PQD (24 hourly)**

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **Energy and meter** | Settlements data, | 10 per cent | > 20 per cent |

27; Telstra, p. 12; Vector, p. 14.

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **theft detection** | power quality data assists | | |
| **Improved ability to connect DER via a greater understanding of local hosting capacity** | Voltage data | 10 per cent | > 40 per cent |
| **Improved visibility, DER hosting capacity and investment planning** | Voltage data | 10 per cent | > 40 per cent |
| **Dynamic export limits (dynamic operating envelopes)** | Voltage data | 10 per cent | > 50 per cent |
| **LV network optimisation – static tuning of voltage management** | Voltage data | 10 per cent | > 50 per cent |
| **Cross-referencing error correction** | Settlements data, power quality data assists | Per unit | Per unit |
| **Neutral fault detection** | Power quality data | Per unit | Per unit |

Source: ENA's submission to the Directions paper, pp. 20-23.

Note: Percentages are indicative based on the best current estimates. Penetrations may vary based on access to smart meters and meter data. ENA has indicated that DNSPs could provide most of these services on 10-20 per cent. However, they could be considered less efficient than the optimal indicative penetration.

#### DNSPs are expected to use 'basic' power quality data for detecting loss of neutral

Detecting neutral integrity is a critical use case that requires continuous access to all smart meters in a local network area (see Box 3). Access to 'basic' PQD under the final recommendation will allow DNSPs to identify and resolve neutral integrity issues – improving consumer safety. We understand that a loss of neutrality can occur slowly over time or suddenly due to a fault or damage. The AER estimates that 0.2 per cent of installations per annum are affected by neutral integrity issues, which could be as many as 15,000 customers each year in the competitive metering states.[239]

PQD is currently being used in Victoria to identify neutral faults. Based on public information from the Victorian advanced metering infrastructure rollout, remote identification of such faults has resulted in material cost savings and improved customer safety :[240]

- **United Energy**: Neutral integrity testing undertaken remotely avoided site visits and manual testing at around 65,000 premises annually, saving about $26 million annually.
- **AusNet**: Identified and remediated more than 1500 loss of neutral situations reducing the number of reported electrical shocks by 75 per cent.
- **Jemena**: Approximately 4105 truck visits per annum have been avoided, with an estimated benefit to all customers in 2016 of $1,654,890.

Informal feedback from DNSPs and submissions to the Draft report indicates that these avoided costs are likely to be comparable in the competitive metering states – based on the per annum frequency that loss of neutrals occurs. For example, Essential Energy said in its submission:[241]

> In the 5 years to 2023, Essential Energy recorded a total of 4,090 customer-reported shocks and tingles on its network, or an average of 677 per year. Investigations found that around one third of these, or an average of 228 per year, were due to network-related issues, including loss of neutrals.

### BOX 3: WHAT IS NEUTRAL INTEGRITY?

Neutral integrity is the condition of a neutral wire in an electrical system. Electrons flow into premises through an active wire or wires, and flow out again through the neutral wire (or vice versa in an AC system), having passed through appliances or other loads along the way.

Loss of neutral is a condition that occurs when the neutral wire becomes disconnected from the electrical network. This can happen due to several factors, such as terminal corrosion, poor installation, or a tree branch pulling on the neutral wire.

The neutral and earth conductors are bonded at the main switchboard at each premise. This means that, if the neutral wire breaks, all earthed components, like the outside of many appliances, can become live, because they are indirectly connected to the active conductor via appliances and loads.

The risk is generally ameliorated by installing a local earth rod, which provides a secondary

239 AER's final decision on the distribution determination that will apply to Powercor for the 2021–26 regulatory control period, Attachment 16: Alternative control services, p. 26.

240 For more information, see here: https://www.energynetworks.com.au/news/energy-insider/developments-in-energy-market-competition-in-victoria/; and here: https://www.esv.vic.gov.au/sites/default/files/2022-12/SPR-Electricity-2016.pdf.

241 Essential Energy submission to the Draft report, p. 15.

path for electrons flowing from the premises. However, an earth rod usually represents a much higher resistance path for electrons travelling back to the LV network, meaning that, when enough load is switched on, earthed equipment can still potentially rise to dangerous voltage levels. The local earth is also sometimes bonded to the incoming main water pipe where available. This helps reduce resistance to earth, but also introduces the potential of livening up taps and sinks.

An additional risk is that a broken connection to an earth rod can easily go unnoticed, because earth rods play no role in power supply under normal conditions.

Other risks beyond electrocution also exist, such as:

- **Unbalanced load**: When the neutral wire is disconnected in a multi-phase installation, it can cause an imbalance in the load on the other phases of the electrical system. This can cause the voltage on those phases to fluctuate, damaging equipment.
- **Fire**: In some cases, a loss of neutral can cause a fire. The high voltage or unbalanced load can cause equipment to overheat and catch fire. A high resistance neutral connection can also generate significant heat directly.

Neutral integrity detection is the process of testing an electrical system to ensure that the neutral wire is in good condition and that there is no risk of a loss of neutral. This testing can be done physically using various methods, such as injecting a current into the neutral wire and measuring the resulting voltage, or can be detected through algorithms applied to PQD.

Source: AEMC

### There are additional benefits: enhancing network visibility and economic efficiency

The Commission's final recommendation for 'basic' PQD sharing promotes the benefits of improving network visibility. This is particularly relevant where the rapid growth of consumer-driven CER presents new challenges for managing localised demand-supply balance and constraints in LV distribution networks. The lack of visibility in this changing network can impact planning, investment, and operation decisions, increasing consumer costs.

The industry is actively working on enhancing how networks are monitored and managed. This includes leveraging data from smart meters, investing in network assets, gathering data from customer devices, and engaging new service providers. Modelling approaches are also being developed and applied to changing distribution system operations. Even with near-universal coverage of smart meters in 2030, we recognise that other devices besides smart meters will be required to share data, including PQD. Smart meters will be one of many data sources in the future grid. DNSPs are expected to and anticipate investments in alternative and complementary devices to gain visibility and understanding of the network, to provide local value.

'Basic' PQD can be re-used and aggregated for multiple purposes, creating positive spillovers for other use cases and improving economic efficiency. These use cases include the tools to plan, forecast, and make decisions accurately. Improved planning and informed investment decisions contribute to the efficient operation and investment in network infrastructure – lowering consumer costs. These use cases are well aligned with consumer preferences and expectations about the benefits smart meters may provide, as indicated by the SEC Newgate Research study (see Box 4).

### BOX 4: 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).

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 as a result.

Source: SEC Newgate Research, Final Report, p. 49.

The insights obtained from 'basic' PQD will enable DNSPs better to understand their network's operating parameters and limitations. This enhanced visibility will enable networks to accept more exports, thereby reducing the need for export limits and integrating CER more effectively. Most of the benefits associated with these use cases experience exponential growth initially, levelling out at higher data penetrations.

'Basic' PQD can play a vital role in compliance and enforcement, improving key areas of CER performance by providing DNSPs with high latency insights into devices connected to the network, including:

- **Meeting regulatory network voltage requirements**: Victorian DNSPs report quarterly on their average voltage data, enabling the Essential Service Commission and participants to make evidence-based policies and regulations. Since starting reporting in 2020, average voltages have been trending down significantly – which can contribute to more solar exports and less energy consumption due to things like better appliance performance.

- **Supporting CER Technical standards compliance :** 'Basic' PQD would reveal local voltage conditions relative to individual CER device's net performance. This would help improve the transparency of CER device compliance with CER technical standards and enable DNSPs to contact non-compliant consumers and assist in rectifying the non-compliant device efficiently and effectively.
- **Dynamic operating envelope conformance monitoring**: DOEs will ensure that the local grid and overall electricity system remain stable and secure. Therefore, it is essential that the customer systems that are enrolled in a DOE comply with the DOE instructions. If the DNSP were to monitor conformance, it could store historical 'basic' PQD to perform ex-post review of CER compliance with dynamic limits. Alternatively, DNSPs could seek the reconfiguration of smart meter alarms to monitor, detect, and alert the DNSP when an NMI breaches an export limit based on data (see appendix E.4.1).

These potential use cases are worth exploring further in the future.

## E.4 Market participants can commercially negotiate 'advanced' power quality data

The Commission considers participants should be able to negotiate the terms, conditions, and prices of 'advanced' PQD services on a commercial basis. The implementation of this position does not require changes to the NER to define 'advanced' PQD (see Box 5). Current arrangements in the NER allow for commercial negotiation of these services on fair and reasonable terms, with changes to 'basic' PQD creating more certainty.[242] Stakeholders have not raised significant concerns about securing efficient access to 'advanced' services — supporting this approach.[243]

### BOX 5: WHAT IS 'ADVANCED' POWER QUALITY DATA?

We propose defining 'advanced' PQD as any service that materially differs from the 'basic' PQD standard, for example:

- **Data resolution:** must include data with higher resolutions or sampling volumes than 'basic' PQD services. For example, 'advanced' PQD services could include sub-second sampling or 1-minute batching.
- **Data frequency:** must be delivered more frequently than 'basic' PQD services. For example, 'advanced' PQD services could be delivered in near-real time.
- **Data delivery method:** can be delivered using methods other than B2B communications or outside the shared market protocol.

242 For example, see NER 7.4.3 (b).

243 Submissions to the Draft report: Ausgrid, p. 2; ENA, p. 5; Energy Queensland, pp. 5, 26; Essential Energy, p. 16; Evoenergy, p. 6; Intellihub, p. 9; Momentum, p. 7; Origin, p. 8; SA Power Networks, p. 15; Secure Meters, p. 10; Shane Rattenbury MLA, p. 2; Vector, pp. 12-13.

- **Data types:** can include data types that are not included in 'basic' PQD services, such as supply frequency, temperature, harmonic distortions, flickers and imbalances, swells and sags, or outage pings.

'Advanced' PQD refers to a more specialised monitoring and analysis level encompassing enhanced data attributes and services beyond the 'basic' PQD standard. 'Advanced' PQD aims to provide more detailed insights into electrical power supply and consumption characteristics, enabling improved diagnostics, proactive management, and power quality optimisation for various applications.

The Commission expects sufficient competition exists in the metering services market for 'advanced' services. DNSPs have enough bargaining power to negotiate access to 'advanced' services, such as through competitive tender processes. We expect parties to adjust the contract terms if their needs change over time. Participants are better placed than regulatory intervention to achieve this outcome. By negotiating the contract terms, both parties can share the risks and ensure maximum value. This will lead to lower costs for consumers.

### E.4.1 There is sufficient competition for these services to be commercially negotiated

The benefits of 'advanced' PQD services may initially increase exponentially but then level off at very moderate penetrations of smart meters. This means that there is a significant benefit to having a reasonable level of coverage, but the marginal benefits of additional meters decrease as the penetration rate increases. Once there is sufficient coverage, DNSPs and other service providers can negotiate fairly with metering service providers to get the best possible deal. This is because there is more competition for the remaining meters, and DNSPs can run competitive tenders as they don't need data from all meter providers.

As shown in Table E.2 below, none of the use cases identified requires 'advanced' PDQ from all metering installations. At a minimum, a DNSP would only need to access 10 to 30 per cent of smart meters in their local network area to provide 'advanced' PQD services. However, some use cases need 50 per cent or more of the smart meters may be necessary to provide optimal customer benefits.

Table E.2: **DNSP use cases that are enabled by 'advanced' PQD (5-minute)**

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **Identifying outages** | Power quality data | 10 per cent | > 30 per cent |

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **when they happen** | | | |
| **Transformer load management** | Voltage data | 10 per cent | > 30 per cent |
| **Real-time low-voltage network visibility** | Voltage data | 10 per cent | > 40 per cent |
| **Dynamic voltage management (real-time)** | Voltage data | > 20 to 30 per cent | > 50 per cent |
| **Accurately identifying outage location** | Power quality data | 20 per cent | > 50 per cent |
| **Rapidly responding to outages (automated)** | Power quality data | 20 per cent | > 50 per cent |
| **Automated transformer load management** | Voltage data | > 20 per cent | > 50 per cent |

Source: ENA's submission to the Directions paper, pp. 20-23.
Note: Percentages are indicative based on the best current estimates. Penetrations may vary based on access to smart meters and meter data. ENA has indicated that DNSPs could provide most of these services on 10 to 20 per cent. However, they could be considered less efficient than the optimal indicative penetration

Other options to monitor PQD exist even if 50 per cent or more of the smart meters in a local network area are required to deliver optimal consumer benefits — presenting further opportunities to reach a competitive price. Using sophisticated sampling, batch testing, or other network or non-network devices may be more prudent and efficient — importantly, meters delivering 'basic' PQD will not be able to achieve these outcomes. DNSPs are already investing in alternative substation devices to improve decision-making with tap settings for transformer load management use cases. There are likely only minor benefits to using data analytics from deeper in the feeder for this decision-making.

#### Per-unit or on-demand services can also be utilised under the current arrangements

We expect these consumable services to be used less frequently and so can be determined through commercial negotiation alongside 'advanced' services. DNSPs have also considered these different services that can leverage existing metering capabilities and market systems in addition to the core functions of the DNSP. Their benefits are linear, improving one-for-one with each additional smart meter installed (see Table E.3).

For example, DNSPs have told us that the outage notification service for off-supply NMIs has a slightly exponential benefit that levels off at higher penetrations.[244] This is because once sufficient coverage exists, most outages can be mapped accurately, and the marginal value of additional meters is minimal.  Further, these use cases are potentially value-adding for consumers and may be offered by retailers, in any case, to attract and retain customers.Another potential use case is meter-level under-frequency load shedding. AEMO's engineering roadmap detailed committed actions for the financial year 2023, including defining emergent power system responsibilities and the adequacy of NEM-wide emergency under frequency management. AEMO is exploring the feasibility of under-frequency load shedding in its general power system risk review – including utilising Victoria's advanced metering infrastructure.

Table E.3: **DNSP use cases that are enabled by other functions**

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **Cost-reflective network tariffs** | Interval energy data (monthly) and power quality data assists | 10 per cent | > 80 per cent |
| **Outage notification service for off-supply NMI's** | Separate outage notification service is pushed when the meter is off-supply | > 0 per cent | > 50 per cent |
| **Remote connection / disconnection** | Existing minimum service specification | > 0 per cent | Not available |
| **Management of controlled load (including DER)** | Existing minimum service specification | > 0 per cent | Not available |
| **Single meter ping** | Meter ping service on demand | > 0 per cent | Not available |
| **Bulk (or area) meter** | Meter ping service on | > 0 per cent | Not available |

244 ENA's submission to the Directions paper, pp. 20-23.

| USE CASES | DATA OR SERVICE REQUIRED | MINIMUM DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER CUSTOMER BENEFITS | DATA PENETRATION REQUIRED FOR DNSPS TO DELIVER OPTIMAL CUSTOMER BENEFITS |
|---|---|---|---|
| **ping** | demand | | |
| **Temperature readings** | Temperature data pushed when the alarm trips | > 0 per cent | Not available |

Source: ENA's submission to the Directions paper, pp. 20-23.

Note: Percentages are indicative based on the best current estimates. Penetrations may vary based on access to smart meters and meter data. ENA has indicated that DNSPs could provide most of these services on 10 to 20 per cent. However, they could be considered less efficient than the optimal indicative penetration

# F MAXIMISING THE FUTURE VALUE OF DATA: CONSUMER ACCESS TO REAL-TIME DATA

This appendix outlines the Commission's final recommendations for enabling consumer access to real-time data from the smart meter. We have identified opportunities and risks within the current regulatory framework for metering services that may not reflect or maximise the value of data to consumers.

We recommend adopting an enabling framework to allow consumers to access real-time smart meter data, such as energy, metering, or power quality data. The purpose of this proposed enabling framework is to set principles, functions, and processes that can be extended to meet specific needs and create an environment for innovation. The objective of the proposed enabling framework should be to ensure access to the potential value of data for consumers, regardless of their technology choices or when they get a smart meter.

Once we receive a potential rule change request, we recommend initiating and further developing this enabling framework through a subsequent statutory rule change process. This will allow detailed design and implementation considerations to be finalised in collaboration with stakeholders. Some of the key features we recommend should be further considered in developing the enabling framework. These are set out below (see Recommendation 5).

## RECOMMENDATION 5: AN ENABLING FRAMEWORK FOR CONSUMER ACCESS TO REAL-TIME SMART METER DATA

1. **Consumer access to real-time data**: Consumers should have access to real-time data from their smart meter installations without incurring direct charges for this access under the regulatory framework for metering services. Additionally, they should be able to share this data with authorised representatives (see appendix F.2).
2. **Expand receiving rights for authorised representatives**: Authorised representatives should have broader access rights to real-time data. Ensuring a level playing field for data access among authorised representatives will promote data-driven competition while safeguarding consumer interests. Metering service provider compensation for authorised representative access should be fair, reasonable, and non-discriminatory in specific circumstances (see appendix F.3).
3. **Futureproof definitions**: We intend to define "real-time" as data delivered within 300 seconds of being generated, but encourage meters to share data as fast as technically possible. This definition allows market participants to offer various services without rigidly defining what "real-time" means (see appendix F.1).
4. **Accommodate new technologies**: The broad design of the access framework should set common objectives and guidelines instead of specifying service pathways (i.e. not prescribing remote or local access). This should enable participants to deliver positive

outcomes while avoiding potential implementation risks associated with a service-specific approach (see appendix F.4).

5. **Consider interoperability as a matter of performance**: Remove barriers to smart meter data access and sharing in the NER, while encouraging participants to adopt interoperability standards already in the energy sector to facilitate interoperable data sharing with other participants and services (see appendix F.5).

We also have an updated position on potential privacy safeguards, following the Draft report recommendation to evaluate consumers' concerns about privacy further (see section).

Our proposed enabling framework draws heavily from two recent European Union (EU) regulations:

1. Proposal for a regulation of the European Parliament and of the Council on harmonised rules on fair access to and use of data (the EU Data Act).[246]
2. Implementing Regulation on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data (the EU Implementing Regulation).[247]

These proposals offer flexible and performance-oriented measures to support efficient data access in the regulatory framework for metering services. We have highlighted throughout this appendix where these EU proposals have influenced our positions to reflect best practice examples.

### The current regulatory settings for metering services may not maximise the value of data for consumers

In this Final report, we have decided to re-establish the purpose and principles for enabling consumer access to real-time data. We have carefully considered previous stages of stakeholder feedback, inputs, and insights, incorporating them in this final recommendation for changes to the regulatory framework for metering services. Through this process, we have re-examined how to maximise the net value consumers can receive from smart metering and consider that enabling greater access to data presents one way to achieve this.

We consider that smart meter data can be non-rivalrous, meaning that it can be reused, shared, and aggregated without losing its original value – instead, reusing, sharing, and aggregating data can generate economies of scale and scope, or network effects as the data is repurposed.

246 Proposal for a regulation of the European Parliament and of the Council on harmonised rules on fair access to and use of data, COM/2022/68. Document 52022PC0068. For more information, see here: https://eur-lex.europa.eu/legal-content/en/ALL/?uri=COM:2022:68:FIN.

247 Commission Implementing Regulation (EU) 2023/1162 of 6 June 2023 on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data C/2023/3477. Document 32023R1162. For more information, see here: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32023R1162.

Under the current regulatory framework for metering services, consumers receive a smart meter on a new and replacement basis. Consumer access to smart meter data is limited to historical billing and settlement data, or representations of estimated consumption data through their retailer's app. The current regulatory framework does not include provisions for consumers to access real-time data transparently, seamlessly, and in an easy-to-understand or useable way.

The current regulatory settings do allow consumers to share historical data with authorised representatives and accredited data recipients under the Commonwealth's consumer data right (CDR) for energy. However, the current settings may not sufficiently enable consumers or market participants to share real-time data in a way that captures potential economies of scale and scope.

There is insufficient clarity and certainty to access and share real-time data in the regulatory framework for metering services. The value customers can receive from smart metering may not be maximised — including potential access to new and innovative services, valuable information about their usage, and enhanced competition for providing services. An enabling framework could rectify this issue, maximising the value of data for customers.

### Enabling greater access to real-time data is likely to promote the long-term interest of consumers

This Review's final report recommends accelerating smart meter deployment, meaning most consumers will receive a smart meter by 2030 (see appendix A). This provides cause to re-evaluate customers' return on investment in smart metering. When it comes to determining the value of data that customers receive for the investment in smart meters, we have identified several opportunities that should be explored because they are likely to promote the long-term interest of consumers, including:

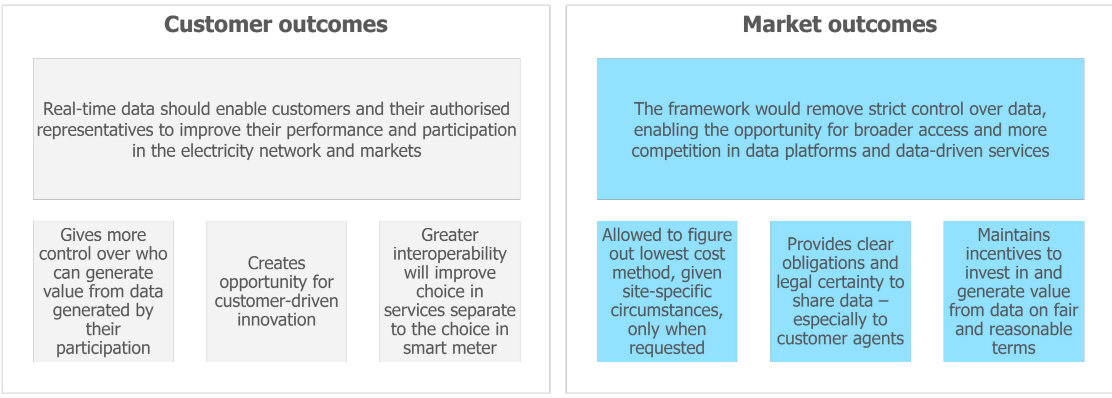
- **Providing certainty of access**: To create a clear and certain framework for data access, we should define who can access data and create consumer value. We also should ensure that consumers have control over their data and are informed about its use. This will help to promote open and innovative data services that benefit consumers and prevent unfair or unreasonable access (see appendix F.2).
- **Ensuring flexibility and adaptability to lower costs**: As indicated above, our final recommendation is to create an adaptable and flexible enabling framework for emerging technologies and advancements. We do not think the framework should prescribe specific data-sharing methods at this stage and should instead highlight the importance of continuous adaptation and foresight in addressing future data-sharing challenges at a lower cost (see appendix F.4.1).
- **Delivering a customer-centric approach to innovation**: Prioritising consumers' choice to receive real-time data and leverage technological investments could enhance consumer engagement. Access to real-time data could allow service providers to tailor solutions that meet consumer-specific needs, driving customer satisfaction. Enabling this

outcome should deliver a customer-centric approach to innovation that best aligns with consumers' preferences (see appendix F.4.2).

- **Establishing clear and certain responsibilities for accessing and sharing data**: The enabling framework that we have recommended should enable customers to access real-time data regardless of their service or meter provider. This should help customers get better insights into their own energy usage and make better-informed choices about their preferred service provider, usage costs, and CER integration. It will encourage market participants to invest in data-driven solutions that benefit consumers rather than simply bundling devices together (see appendix F.3).
- **Contributing to current and emergent use cases**: Real-time smart meter data will likely be integral to several existing and emergent use cases, for example, demand response and management, cost-reflective pricing and tariffs, CER optimisation and flexibility. The potential value of real-time data as an input into these use cases could be material, ensuring accuracy when participating in time-sensitive programs like demand-side participation or dynamic operating envelopes. While certain use cases can be achieved without real-time data from the smart meter, these present trade-offs in costs, availability, and responsiveness (see appendix F.1.2).
- **Enabling new experiential services**: Data is a critical input into data-driven applications and platforms that focus on the customer's experience interacting with the service. Newgate Research shows that experiential services, such as personalised energy consumption insights, real-time tips, and recommendations to help users make informed decisions about energy usage, materially improving customer sentiment towards smart meters.[248]
- **Unlocking high-potential long-term innovations**: Fair and open access driven by customer choice could lead to more competition and innovation in the energy sector – lowering barriers to consumers participating in the energy transition through new use cases such as home automation and algorithm-based flexibility, community energy sharing, and integration with other digitalised sectors like climate technology, artificial intelligence, and transport (see Box 7).

248 SEC Newgate Research, Final report, p. 49.

**Figure F.1: An enabling framework could be beneficial for both consumers and the market**




AEMC

### Balancing opportunities and risks: stakeholder perspectives on data sharing

Addressing data access and responsibility challenges will likely lead to significant benefits. Our final recommendation to develop the enabling framework seeks to balance the potential opportunities for the future while being pragmatic and realistic. Stakeholders have contributed to this final recommendation through responses to the Draft report; the feedback provided in response to the Draft report was broadly consistent with key themes identified in previous stages:[249]

- **Building trust and engagement**: Advocates of customer access to real-time data highlight its potential to enhance consumer trust and engagement. By providing timely and accurate information, consumers can make informed decisions, monitor their energy usage, and actively participate in demand flexibility services.
- **Demonstrate merit and demand**: Concerns are raised by several stakeholders regarding the long-term benefits and necessity of regulatory intervention in accessing real-time data. These stakeholders consider that existing products and offers already meet consumer needs, and there needs to be more evidence of a substantial need or want for additional that justifies regulating access (see above).
- **Formalise data ownership and consumer control**: Some stakeholders submitted that smart meter data is consumers' property: it is essential to acknowledge their right to access, manage, and share their data as they deem appropriate. The regulatory framework for metering services should empower consumers to have more control over data, fostering more competitive and customer-driven services (see appendix F.2).

249 Submissions to the Draft report: ACOSS, p. 23; AEC, p. 2; AER, p. 11; AGL, pp. 17-18; Alinta, p. 9; Ausgrid, p. 12; CEC, p. 4; ECA, p. 13; EDMI, pp. 17-18; EWO joint submission, p. 9; Energy Queensland, p. 33; EnergyAustralia, p. 6; Essential Energy, p. 15; Evoenergy, p. 7; Green Metering, p. 19; Intellihub, pp. 13-14; Momentum, p. 7; Origin, p. 8; PIAC, p. 30; PLUS ES, p. 29; Red and Lumo, p. 5; Rheem and CET, p. 4; SA Power Networks, p. 15; SwitchDin, p. 5; Vector, p. 15; Watt Watchers, pp. 4-5.

- **Support further exploration**: Certain stakeholders support conducting additional investigations and research into access to real-time data, emphasising the importance of gaining further understanding. We consider that there will be opportunities in any subsequent statutory rule change process to explore the opportunities and risks further.
- **Take an organic market-driven approach**: Some stakeholders contend that access to real-time data will naturally evolve without requiring extensive regulatory intervention: market forces and technological advancements will drive the development of desired functionalities in a self-regulating manner (see appendix F.4).

## F.1 What do we mean by "real-time"?

We recommend that the enabling framework's definition of "real-time" should be a range. Practically, this means defining real-time data to encompass a minimum and maximum range of delivery times. A defined range should be reasonably futureproof, acknowledging the dynamic nature of technology. It should also seek to balance operational feasibility and ambition, promoting consumer's interests through practical and adaptable innovation.

At a minimum, we recommend that data delivery should not exceed 300 seconds (or 5 minutes). This would align the enabling framework with market settlement while allowing for a reasonable degree of latency in the communications method (see Table F.2). This practical baseline ensures that many applications can benefit from the defined standard without imposing overly stringent requirements.

The enabling framework should set an aspirational maximum target for smart metering technology to deliver data as close to instantaneous as technically possible. This would align the enabling framework with the ever-evolving landscape of technology. As smart meter technology and data processing systems continue to advance, this approach allows for incorporating innovative solutions that can achieve faster data delivery over time. By not prescribing an exact maximum, the enabling framework should promote future readiness and avoids becoming obsolete as technology progresses.

A more rigid or narrow definition could lead to implementation challenges and unnecessary operational costs. Instead, a flexible range in the enabling framework should account for potential variations in technical capabilities, fostering smoother adoption of real-time data and data-driven services by customers. The definition offers clear boundaries while accommodating different use cases. It acknowledges that data delivered in different time scales apply to different use cases (see appendix F.1.2)

This recommendation is consistent with the EU Implementing Regulation, which defines "near-real-time" as metering and consumption data provided continuously by a smart meter in a short period, usually down to seconds or up to the imbalance settlement period in the national market, which is five minutes in the NEM. The metering and consumption data is also non-validated and made available through a standardised interface or through remote access per the meter's minimum functionality.[250] This definition provides clarity on what we

250 European Commission, Implementing Regulation, June 2023, p. 6.

understood as the potential range for data delivery, both influencing and reinforcing our approach.

### F.1.1 Stakeholders sought clarity on the meaning of "real-time"

In response to our Draft report, stakeholders expressed the need for further clarity on the definition of "real-time" data. These submissions sought to understand the technical nuances of the definition, including:[251]

- **Time intervals and network latency:** Stakeholders questioned whether the "real-time" data definition, specifically the threshold of less than five minutes, accounted for network latency. They sought clarification on whether this threshold factored in the time it takes for data to travel through networks and systems, affecting the actual time of data availability and processing.
- **Distinguishing between short interval data:** Stakeholders also sought clarity on distinguishing between two types of short interval data: data taken at intervals of five seconds or less that is provided ex-post (after the event) and data recorded and provided in equally short intervals. The relevance of these distinctions to the "real-time" data definition was of interest to stakeholders.
- **Threshold and market settlement:** The relevance of the five-minute threshold in relation to market settlement processes was queried. Stakeholders questioned whether this threshold was chosen to align with market settlement timing and the potential implications of choosing shorter intervals, such as one-minute data, for future markets or services.

In considering these submissions, the Commission has clarified that the definition of "real-time" data should encapsulate a range of time intervals that align with various operational contexts while maintaining practical feasibility. This includes recognising that network latency can influence the time data becomes accessible and focusing on the time it takes for data to become available for analysis and use after it's generated. While these technical parameters may change as technology advances, the 300-second minimum threshold should remain aligned with current operational practices and market settlement processes.

### F.1.2 Why might we need or want "real-time" data?

Real-time smart meter data could be integral to several emergent use cases for electricity consumers, such as demand response and dynamic operating envelopes. In the right use cases, real-time data will likely enable (see Figure F.1):

- Accuracy by using the pattern-approved measurements of smart meters as a reference point for changes in usage patterns, on-site generation, and grid conditions. This enables consumers and service providers to see the consumer's energy performance accurately.
- Optimisation and participation in the electricity network and markets of energy usage by facilitating timely decision-making. With real-time data, consumers and intelligent management devices can identify energy-intensive activities, adjust usage patterns, and

251 Submissions to the Draft report: CEC, pp. 3-4; EDMI, p. 1; Secure Meters pp. 11-12; SwitchDin, pp. 12-13.

promptly respond to minimum or peak demand periods. This optimisation minimises wastage and reduces electricity costs.

- Participation in time-sensitive programs like demand-side participation or dynamic operating envelopes by providing insights into grid conditions. Consumers can adapt their energy usage based on real-time signals, contributing to grid stability during peak periods or when renewable energy generation is at its peak. This level of responsiveness is unattainable with historical data alone.

After preparing the Draft report, we engaged with interested parties, including the CEC, to better understand what "real-time" means for potential users and why it matters in different scenarios (see Box 6).

### BOX 6: FINDINGS FROM WORKSHOPS WITH CEC MEMBERS

Workshop participants identified two key areas where real-time data could be used to provide benefits to customers (consistent with Figure F.1):

1. **Services upstream from the meter**: Activities that help manage the electricity distribution system and the wholesale market, including responding to dynamic limits, reducing congestion, and minimising network losses.
2. **Services downstream from the meter**: This includes services that can help customers save money on their electricity bills, such as maximising the energy produced by CER for their consumption or as an input into home energy optimisation.

The workshop participants also made the following comments:

- **Power quality data is an important input to future use cases**: Ultimately customers want to see a reduction in their dollars per kilowatt hour (which is energy and settlement data). For this purpose, they could see estimated consumption data; however authorised representatives could use PQD to identify problems with the electricity supply and improve the customer's electrical performance beyond shifting consumption and exports.
- **Real-time data could be a range, rather than rigid**: Smart meters can collect data at a very high frequency, often sub-second. Workshop participants agreed that future needs do not necessarily demand data that fast. Data every five minutes is enough for most uses, as that is how often the market settles. A one-second delay could present a present technological maximum in decision-making software (see above).
- **Existing authorisation may be suitable for third-party access**: We could rely on authorised representatives to access customer data. The workshop participants agreed that this might be fit for purpose, but further changes to ensure data accreditation would benefit consumers and the broader industry (see appendix F.3.1).
- **New direct costs should be compensated fairly and reasonably**: The workshop participants agreed that, where there are genuine direct costs associated with providing access to customer data, such as developing an application programming interface,

compensation should be on a fair, reasonable, and non-discriminatory basis (see appendix F.3.3).

- **Being "outcomes-focused" may require more detail:** The enabling framework we have recommended could be outcomes-focused. This means that the focus should be on ensuring customers have access to the data they need to make informed decisions about their energy use. One material risk that many participants identify is access being open to interpretation, necessitating a reference implementation model (see appendix F.4).

While the Commission acknowledges that certain use cases (such as responding to time-of-use pricing and scheduling appliances) can be achieved without real-time data from the smart meter, there are trade-offs, for example, in cost constraints and potential response optimisation. Not all situations call for real-time data: using real-time data to forecast energy demand or distribution network planning requirements may be impractical. In these cases, alternative data collection methods with different time scales can still be used to generate accurate and useful insights.

Other data collection methods with different timeframes can still help consumers. For example, the former ESB's Network Visibility Consultation paper showed that people are more interested in predicting network conditions than getting real-time data. This means looking at how the network operates over time, including recent data, to spot trends and make smart choices about energy use.[252] In the same way, the Commonwealth CDR for energy gives consumers access to their energy consumption history. A historical view of energy performance is crucial to consumers making informed decisions and performing actions around energy plans and service providers.

Different use cases need different timescales. Real-time data may be integral to future use cases like demand-side participation or dynamic operating envelopes but not every use case. While these use cases can deliver customer benefits using slower timeframes, not having real-time data could potentially mean less accuracy, slower responses, and less ability to optimise.

## F.2 Consumer access should be a core feature of the enabling framework for real-time data

Consumer access to real-time data from smart meters should be a core feature of the regulatory framework for metering services. Clear provisions in the NER providing for this access can promote certainty of access by establishing clear and certain responsibilities for accessing and sharing data. Specifically, we recommend that the enabling framework:

- Place new obligations on retailers and metering service providers (see appendix F.2.1).
- Consider new information requirements to improve the consumer experience (see appendix F.2.2).

252 ESB, Benefits of increased visibility of networks, Consultation paper, July 2023, pp. 11-12, 34.

- Consider preventing consumers from incurring direct charges for real-time data access (see appendix F.2.3).

We expect customers to increasingly seek real-time energy and metering data, which differs from the validated historical settlement data they can receive through their retailer. This is because we expect consumers can use real-time energy data to improve their performance and participation in the electricity network and markets: optimising cost, comfort, and sustainability (see Figure F.1). Some use cases may require real-time PQD to respond rapidly to grid fluctuations, minimising losses and constraints and enhancing stability (see Box 6).

Data-driven services help households identify and reduce energy costs. The SEC Newgate Research study found that people are more likely to support the adoption of smart meters if they believe they will receive new, experiential services that can help them save money and reduce their environmental impact.[253] Smart meters turn power into the information that can drive these benefits that consumers are likely to support.

### F.2.1 New obligations should be placed on data holders to make data available where it is requested

We recommend that retailers and metering service providers be required to provide real-time data to consumers upon request, in addition to the current obligation to provide historical data.[254] However, we recommend this obligation is considered a best-endeavours basis, as provisioning access to real-time data may be challenging in some cases, depending on the location of the meter.[255]

Today, retailers must provide metering data to a retail customer or customer-authorised representative, electronically or physically – depending on the customer or customer-authorised representative's formatting request. In these circumstances, the MP is the service provider of data to the retailer. Retailers must use reasonable endeavours to respond within a specific period of time – 10 business days for a single retail customer and 20 business days for more than one retail customer.

In appendix F.4.2, we discuss how these current arrangements and processes could be leveraged to practically activate real-time data from the smart meter – so that these regulatory obligations can be met. Further consideration is required to ensure these new obligations increase regulatory certainty for consumers to access data generated by the smart meter. The EU Data Act's Article 3 shows how these new obligations could be achieved by setting a general framework that addresses the conditions under which data is available.[256] Further, the EU Implementing Regulation provides a reference model to meet regulatory obligations. The reference model outlines common rules and procedures for the business, function and information layers, in line with national practices.[257]

253 SEC Newgate Research, Final report, p. 49.

254 See NER 7.14 and the Metering Data Provision Procedures, here: https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/metering-procedures/2021/metering-data-provision-procedures-v20.pdf?la=en.

255 Further consideration is necessary to determine the delivery of obligations to provide real-time data to customers, which may only apply to the meter. The customer may be responsible for the cost of installing the necessary wiring to connect their router to the meter. This is analogous to the consumer's installation for electricity — the customer is responsible for all wiring in their premise (see Table F.2).

256 European Parliament, Data Act, 2022, p. 44.

### F.2.2 Customers should be more informed about data access to make more informed choices

Under the current framework retailers must identify and publish, at a minimum, the information required from a retail customer or customer-authorised representative who requests metering data.[258] It is up to the retailer to market or promote the uptake of historical data.

The Commission considers that, for real-time data, more information may be necessary to support and encourage consumers to access real-time data — which could be a way of earning and maintaining social licence for an accelerated smart meter rollout. Further development of and consultation on the information necessary to enable customers to make informed decisions is required.

As one best practice example, the EU Data Act places additional obligations on service providers to support the user experience, including:[259]

- Manufacturers and designers have to design the products to make the data easily accessible by default, and they will have to be transparent on what data will be accessible and how to access them.
- Before concluding a contract for the purchase, rent or lease of a product or a related service, at least the following information shall be provided to the user in a clear and comprehensible format:
  - the amount of data produced by the customer's participation,
  - whether it is generated continuously and in real time,
  - how the user may access those data,
  - whether the manufacturer or third party uses the data,
  - whether the seller, renter, or lessor is also the data holder. If not, the user should be told the trading name of the data holder,
  - the means of communication between the user and data holder,
  - how the user can request the data are shared, and
  - the user's right to lodge a complaint.

Obligations to improve the user experience are also found in the EU Implementing Regulation, whereby the data access provider should make all relevant procedures and means publicly available for final customers to access their data without unnecessary delay.[260]

### F.2.3 Consumer access could be free of direct charge

The enabling framework for real-time data should consider the allocation and recovery of costs to provide data. It should consider a balance between consumer access rights, effective levels of choice and competition, and innovation potential. These issues should be considered

257 European Commission, Implementing Regulation, June 2023, p. 3.

258 For more information, see NER/NERR. This information is used to verify identity and relevant consent from customers or customer authorised representatives. Again, the MDP is the service provider of the data to the retailer.

259 European Parliament, Data Act, 2022, p. 14.

260 European Commission, Implementing Regulation, June 2023, pp. 8-9.

further under any potential subsequent statutory rule change process, including alternative options.

Under the current regulatory settings, consumer requests for historical billing data are provided free of charge – with some exceptions.[261] These settings provide regulatory thresholds in the allocation and recovery of costs. It also introduces the potential for price competition, where different retailers could provide historical data at a lower cost, including for free.

The Draft report did not consider the allocation and recovery of costs in detail, instead focusing on service pathways for consumers to access real-time data. One option considered was an 'optional extra', similar to carbon offsets included on a consumer's monthly bill.[262] This approach would lean heavily on potential price competition between retailers, including potentially not charging directly for data.

Our final recommendation for an enabling framework differs from the Draft report — seeking to provide clear and certain access to the consumer, removing regulatory barriers and encouraging widespread adoption and use cases (see Figure F.1). In principle, we consider that consumers' access to real-time data could be free of direct charge. The incremental costs for metering service providers to give access to the consumer could be recovered through the charges to the retailer. A direct charge to consumers for access may hinder consumer choices in upstream or downstream services. This recommendation is also consistent with the EU Data Act's Article 4, which states that the data holder shall make available to the user the data generated by using a product or related service free of charge.[263]

## F.3 Authorised representative access should also feature in the enabling framework for real-time data

The value of data may be maximised by an authorised representative receiving data on behalf of the customer. The Commission does not expect all consumers to have the time or preference to monitor data about their electrical performance in real-time, such as on a smartphone application. Instead, third-party systems or other intelligent electrical devices will be able to collect and analyse real-time data more quickly and effectively. Other systems and devices will be able to identify patterns and trends in the data, providing the consumer with value-added insights and optimisation. Automated processes could even take actions based on the data that are not dependent on the consumer watching it. This presents an opportunity to grow data-driven services and innovations (see Figure F.1).

Given this, we recommend that the regulatory framework for metering services should be purposeful about the obligations to receive data and make data available, and should seek to establish a level playing field for competition while safeguarding consumer interests. The

261 For example, see NERR 56A (3). Exceptions include where the customer has requested historical data multiple times in one year, their request deviates from the metering data provision procedures, or the request is in relation to bulk data requests from more than one small customer.

262 AEMC, Metering Review, Draft report, pp. 117-118.

263 European Parliament, Data Act, 2022, p. 41.

Commission is of the view that further consideration of the following features of the framework are required:

- Consumers can share real-time data with authorised representatives (see appendix F.3.1).
- Authorised representatives can receive real-time data – with additional responsibilities (see appendix F.3.2).
- Fair, reasonable, and non-discriminatory compensation with the potential for dispute resolution (see appendix F.3.3).

### F.3.1 Authorised representatives should be able to request and receive real-time data on the customer's behalf

The enabling framework should allow customer authorised representatives to request and receive real-time data on the customers behalf. This is conceptually similar to the current regulatory framework for historical data requests.[264] Practically, the authorisation to request data could be linked to a contractual agreement, or to an explicit clause within the contractual agreement between the customer and their authorised representative. Retailers and metering service providers could provide authorised representatives with data similarly to processes outlined in the metering data provision procedures.[265] Further consideration is required in relation to the detailed implementation of these recommendations, to allow retailers and metering service providers to develop efficient systems and processes to respond to real-time data requests in a timely manner (see Figure F.3).

The Commission considers that the enabling framework could significantly impact competition and innovation – encouraging new entrants and energy service providers. Easier data access for these businesses would allow them to develop new products and services more quickly and efficiently. This potential opportunity is consistent with feedback from a workshop with Climate Salad members (see Box 7 below).

#### BOX 7: FINDINGS FROM A WORKSHOP WITH CLIMATE SALAD MEMBERS

We hosted an online workshop with some Climate Salad members. Polling results from that workshop indicate:

- **Strong support for open access**: 77 per cent of participants said that open access to real-time data could "definitely" drive innovation in the climate technology ecosystem. This suggests that open access could support competition and innovation, with real-time data providing a solid foundation for developing climate-related technologies, enabling more effective decision-making.
- **Barriers to interacting with the current regulatory framework:** Only half of the participants polled had tried engaging with the current regulatory framework. Participants

264 For example, see current NER 7.15.5; Chapter 10 definition of *customer authorised representative*: A person authorised by a retail customer to request and receive information under Chapter 7 on the retail customer's behalf.; and NERR 56A (3).

265 For more information, see here: https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/metering-procedures/2021/metering-data-provision-procedures-v20.pdf?la=en.

indicated that providing services or partnering with existing providers can be difficult and costly, underscoring issues with the current data-sharing arrangements.

- **Cautious about downside risks:** 60 per cent of participants indicated that a change in access to real-time data could be positive for their start-up, enabling them to create innovative solutions and align their strategies with the changing regulatory framework. 40 per cent of participants were mindful of downside impacts like complex implementation, integration issues, and ongoing expenses that can be material for start-ups.
- **Potential for increased data needs:** More participants thought that access to real-time data would increase their data needs rather than decrease them. This could indicate that start-ups foresee greater demand for data-driven services in their products or concerns about scalability.

Further consideration of this feature of the enabling framework could consider the EU Data Act's Article 5, which states that upon request by a user or by a party acting on behalf of a user, the data holder shall make available the data generated by the use of a product or related service to a third party, without undue delay, free of direct charge from the data holder to the user, of the same quality as is available to the data holder and, where applicable, continuously and in real-time.[266] There would still be direct costs of providing access, which under the Data Act, could be attributable to the third party acting on behalf of the customer which is discussed appendix F.3.3.

### F.3.2 Expanding the receiving rights of authorised representatives should come with additional responsibilities to protect consumer interests

The regulatory framework should consider broadening and expanding the authorised representatives' right to receive real-time data. We are not proposing to create a new market participant category or formal authorisation process at this stage. Instead, we consider that existing rules, guidelines, and procedures should be explored to accommodate these receiving rights. Practically, authorisation could be linked to a contractual agreement, or to an explicit clause within the contractual agreement between the customer and their authorised representative.

Additional responsibilities on customer-authorised representatives to receive real-time data may be necessary to safeguard consumers' interests — which is consistent with the views of potential service providers (see Box 6). This should be further considered in any rule change process. Such an approach would be consistent with Article 6 of the EU Data Act:

266 European Parliament, Data Act, 2022, p. 41-42.

**Table F.1: How the EU Data Act's receiving rights might apply in the Australian regulatory framework**

| RELEVANT CLAUSES FROM THE EU DATA ACT | APPLICATION IN THE AUSTRALIAN REGULATORY FRAMEWORK |
|---|---|
| The third-party must not:<br>• Try to force, trick, or mislead users in any way. This includes using digital interfaces to control or influence users' decisions.<br>• Use the data it receives to create profiles of individual users. This is only allowed if it is necessary to provide the service the user requests.<br>• Share the data it receives with other third parties unless it is necessary to provide the service requested by the user. This includes sharing data with companies that provide core platform services, such as social media platforms or search engines.<br>• Use the data it receives to develop a product that competes with the product from which the data originated. It also cannot share the data with another third party for this purpose.<br>• Prevent users from sharing the data they receive with other parties. This includes preventing users from sharing the data through contractual agreements. | Authorised representatives:<br>• Must formally engage the customer, and obtain voluntary, informed, current, specific, and unambiguous consent.<br>• Must not exploit or coerce the customer into providing access to their data, including by being misleading, deceptive, or withholding services.<br>• Must not use data accessed on behalf of the customer to compete directly with metrology or offer products or services similar to core metering services.<br>• Can use data for competition in upstream and downstream services complementary to metering services or that offer value-added services to customers.<br>• Should be Australian Energy Sector Cyber Security Framework accredited.<br>• Must not share data with Australian Competition & Consumer Commission's Designated Digital Platforms. |

Source: European Parliament, Data Act, 2022, p. 43

Note: For more information on the AESCSF, see here: https://www.energy.gov.au/government-priorities/energy-security/australian-energy-sector-cyber-security-framework.

Note: For more information on Designated Digital Platforms, see here: https://www.accc.gov.au/by-industry/digital-platforms-and-services.

### F.3.3 Potential for fair and reasonable compensation from authorised representatives representing more than one customer

Further development of the enabling framework is required to consider the arrangements between a customer's multiple agents in more detail. Two features of general data-sharing frameworks are likely to help these arrangements and promote consumers' interests. These include:

- The allocation and recovery of costs to provide data.
- Potential for dispute resolution where parties may fail to agree.

The intention of these two features is to prohibit parties from charging excessive fees for data access or unilaterally dictating the terms of access. These outcomes would not be in the long-term interest of consumers. For example, metering service providers should not restrict authorised representative data access after the initial request by imposing limitations on data usage or exorbitant fees. Similarly, authorised representatives should not be allowed to impose terms on metering service providers, such as requesting data unrelated to the customer's needs for their gain.

**The allocation and recovery of costs to provide data**

In principle, we consider that metering service providers should be entitled to recover new and direct costs incurred and investments required for making real-time data available to authorised representatives – but not for the data itself and not directly from the customer. This ensures that interests are balanced between the customer's agents, promoting fair competition between service providers. This also incentivises metering service providers to invest in the infrastructure and systems needed to make data available to authorised representatives. These requirements may necessarily differ from a consumer recovery and allocation of costs (see appendix F.2.3), indicating different direct costs; however, we consider this is consistent with views of potential service off-takers (see Box 6).

Authorised representatives will likely represent more than one customer when providing use cases driven by real-time data. Under the current NERR, this would provide a basis for charging authorised representatives for requesting historical data.[267] We propose that this could be a reasonable starting point under a potential enabling framework for real-time data sharing. Further consideration of an enabling framework for real-time data should consider extending these thresholds, ensuring that any terms and conditions, including compensation, agreed upon between the customer's agents are fair, reasonable, and non-discriminatory.

The EU Data Act defines direct costs as data reproduction, electronic dissemination, and storage expenses, excluding data collection or production costs. Furthermore, the EU Data Act states that direct costs should be limited to the share attributed to individual requests, assuming that the setup of technical interfaces or related software connectivity is permanent.[268] With these in place, the EU Data Act provides the principles and objectives by which compensation is agreed between a data holder and a third-party data recipient.[269]

**Dispute resolution where parties may fail to agree**

We recommend further exploring the need for a potential dispute resolution process in real-time data sharing. Further consideration should consider Article 10 of the EU Data Act as one best practice example.[270]

Dispute resolution processes could address scenarios where parties fail to agree on access terms and conditions, including compensation. To facilitate dispute resolution, service

267 For example, see NERR 56A (3).

268 European Parliament, Data Act, 2022, p. 27.

269 European Parliament, Data Act, 2022, pp. 44-45.

270 European Parliament, Data Act, 2022, p. 45.

providers should provide authorised representatives with a detailed basis for calculating compensation, enabling recipients to verify the fairness of the charges. Additionally, the burden of proof should be on the service providers to demonstrate that prices or contractual terms are non-discriminatory.[271]

Dispute resolution processes should solely focus on the terms of access and their fairness, reasonableness, and non-discrimination. By focusing on the fairness of the charges, the dispute resolution process can help to ensure that customers are not overcharged for data-sharing services — promoting fair competition between service providers. This would mean the dispute resolution process should not focus on technical data-sharing issues. These issues will likely be complex and difficult to resolve through dispute resolution processes. This should promote cooperation between metering service providers and authorised representatives, but also ensure disputes are resolved in a timely manner.[272]

## F.4 An outcome-focused approach to access methods will promote flexibility and consumer interests

We recommend that the enabling framework for access to real-time data be outcome-focused. This approach would allow for adaptation to the evolving technological landscape, prioritisation of consumer needs, and collaboration among market participants — helping to keep costs down and ensure that the framework is responsive to the needs of consumers and their agents.

Practically, this means that the regulatory framework should prioritise defining desired outcomes and functions necessary to provide consumers with access to real-time data. We do not recommend a specific service pathway, such as remote access or local access (unlike the Draft report).[273] Instead, we consider that the design of the enabling framework could be flexible enough to accommodate a variety of service pathways, as needed. Based on our understanding of current technological capabilities, this approach should allow us to achieve positive outcomes while avoiding potential implementation risks associated with a highly service-specific approach, including:

- **Being flexible and adaptable**: The enabling framework allows for incorporating emerging technologies and future advancements by not prescribing specific technologies or data methods. This ensures that the regulatory framework for metering services remains relevant and adaptable to the changing energy market landscape at a lower cost.
- **Taking a customer-centric approach**: Consumer needs and preferences are ever-evolving. An outcome-focused approach ensures that solutions remain aligned with these changes. The enabling framework should prioritise the consumer’s choice and preferences by leveraging latent technologies - tailoring solutions that meet consumer’s specific needs, enhance engagement and satisfaction by aligning with their preferences.

271 Ibid.

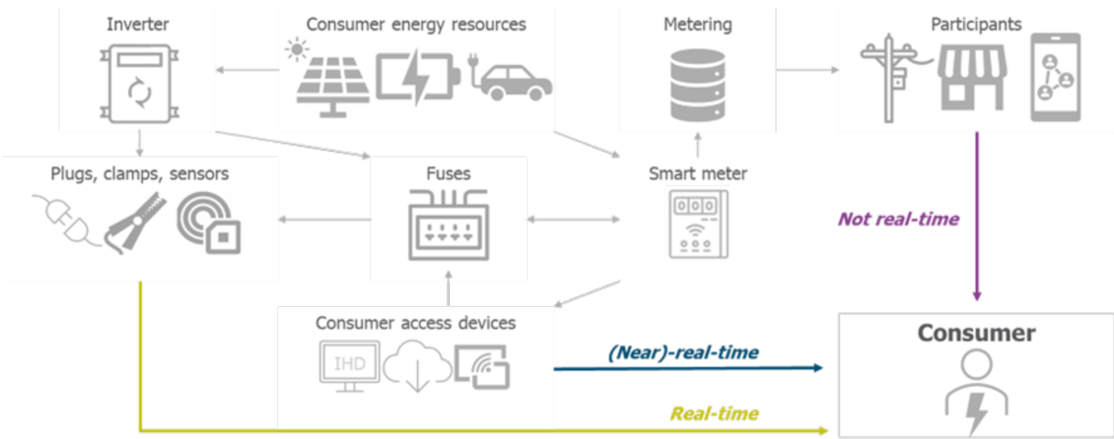
272 Ibid.

273 AEMC, Metering Review, Draft report, p. 114.

- **Promoting collaboration and partnerships**: An outcomes-focused approach fosters collaboration among market participants, technology providers, and consumers. It encourages partnerships and ecosystem-building to provide customers with access to real-time data. A collaborative ecosystem ensures that the consumer's journey remains smooth and holistic — by exploring innovative solutions, sharing expertise, and collectively enabling data-driven use cases to be provided seamlessly.

Consumers should be able to leverage the data access method that the smart meter provides and best suits their needs, preferences, or electrical situations (see Figure F.2).

**Figure F.2: There are many different ways that consumers can obtain real-time data**




Adapted with prior written consent from LCP Delta, Real time energy data: What role does it play for energy insights services?

This approach to not prescribing a data delivery pathway is consistent with the EU Data Act, which allows products to be designed to make certain data directly available from on-device data storage or from a remote server to which the data are communicated.[274] Access to the on-device data storage may be enabled via cable-based or wireless local area networks or networks connected to a publicly available electronic communications service or a mobile network.[275] The product may also be designed to permit the user or a third party to process the data on the product or a computing instance of the manufacturer. The EU Data Act then relies on requirements in it's Article 3, such that products and related services be designed and constructed so that users can easily and securely access any data generated.[276]

### F.4.1 Stakeholders are split with regard to service-specific requirements

The Draft report proposed a service-specific approach to real-time data, consisting of two separate service pathways: remote access and local access.[277] Some stakeholders expressed

274 European Parliament, Data Act, 2022, p. 21.
275 Ibid.
276 European Parliament, Data Act, 2022, p. 40.
277 AEMC, Review of the regulatory framework for metering services, Draft report, 3 November 2022, p. 114.

significant concerns regarding the potential implementation risks and complications associated with this approach:[278]

- **Implications on existing infrastructure**: Implementing service-specific access may require costly upgrades to existing meter fleets, posing challenges related to hardware, software, wiring, rectification, and cybersecurity risks. This could result in substantial financial burdens for providers and consumers without a clear justification.
- **Lack of established use cases and standards**: Tangible use cases and standards for real-time data access were lacking according to some stakeholders, leading to uncertainties and potential costs without a clear benefit — meaning that the risk of implementation failure under a service-specific approach could be high.
- **Technical challenges and security risks**: Service-specific access requirements raise concerns about authorising and controlling data access, reconciling billing data, cybersecurity vulnerabilities, potential misuse of data, and ensuring continuous service.

Some stakeholders agreed with the service-specific approach, urging the Commission to ensure every smart meter has a physical local access port available to the consumer, including to:[279]

- **Avoid potential gatekeeping**: Stakeholders stress the importance of recognising the consumer's right to access real-time data locally from their meter. Establishing local access prevents the potential for "gatekeeping" of consumer data via particular methods. When data holders require access to the meter in one way, this negatively affects competition, potential innovation, and consumer choices in secondary markets (see appendix F.5)
- **Require the most efficient route**: Local access to data enables customers to receive immediate feedback on their energy use due to the lower latency. Data arriving quicker improves customer decision-making around energy performance and supports the development of novel business models focused on customer energy management.
- **Futureproof the meter**: Local access methods, particularly Ethernet and recommended standard serial cables, have proven resilient to technological change. Ensuring that smart meters are capable of these methods would future-proof data access according to some stakeholders. Consumers will continue to have access through standard methods even while the energy landscape changes. Stakeholders recognise the need for minimum standards to ensure compatibility across different meter models and providers.

### F.4.2 Smart meters are capable of multiple local data methods: access is the issue

To strike a balance between stakeholder views listed above, we have chosen to re-establish the purpose and principles for enabling consumer access to real-time data. We have carefully considered stakeholder's inputs and insights, incorporating them in this Final report's

278 Submissions to the Draft report: AGL, pp 18-19; EnergyAustralia, p. 6; Energy Queensland, p. 32; Green Metering, p. 20; Intellihub, pp. 13-14; Origin, p. 8; Telstra, p. 14; Vector, pp. 16-17.

279 Submissions to the Draft report: CEC, p. 4; ECA, p. 13; ETU, p. 20; EDMI, pp. 19-20; Momentum, p. 7; PIAC, pp. 31-32; Rheem and CET, p. 5; SwitchDin, p. 14; Secure meters, pp. 11, 14; SATEC, pp. 5-6; Telstra, p. 13; Watt Watchers, p. 7.

recommendation. The shift away from service-specific options in the Draft report is consistent with this final recommendation's shift toward an enabling framework.

Taking an outcome-focused approach should be more flexible in implementation, prioritising consumer preferences and needs, while encouraging partnerships and ecosystem-building to achieve desired outcomes collectively: delivering consumers access to real-time data.

Smart meters can provide real-time data in many ways, each with advantages and disadvantages (see Figure F.2 and Table F.2). Regulating a single data-sharing method is not likely to be in the long-term interest of consumers. Regulating one solution for access would place the risk of ensuring that meters are sufficiently designed to meet some consumers' needs on all consumers. Technology and consumer preferences evolve rapidly. If the selected method becomes outdated or no longer meets consumers' evolving needs, consumers are left with outdated technology and might need to invest time and resources to update or replace their technologies. Consumers could end up incurring costs associated with upgrades, replacements, or workarounds if the selected method proves insufficient over time.

We recommend that is more prudent for industry participants to face the risk, not consumers. Industry participants should ensure that the installed smart meters are technically feasible and align with consumers' desired outcomes. Participants are more equipped to manage the risks and have the incentive to deliver technical functions that meet consumers' interests. This includes realising competition-driven incentives to ensure the functions they install most effectively meet customer needs. Otherwise, we consider that participants should face the risk that an existing smart meter could get displaced. The potential for displacement encourages industry players to stay attuned to consumer needs and technological advancements — especially compared to individual consumers.

**Table F.2: Different methods for local access and how they compare on key themes**

| **What we're calling it** | "New wires" local access using physical wires to connect devices like Ethernet, optical readers, and RS serial cables. | "Wireless" local access using radio waves to connect devices like Bluetooth, cellular 4G/LTE, ZigBee, IEEE 2030.5, TCP/IP SSL LoRaWAN, and Wi-Fi / Wi-SUN. |
|---|---|---|
| **Data transfer rate** | High, often 100 gigabits per second over short distances. | Moderate to high transfer rates over longer distances. |
| **Reliability** | High reliability – not susceptible to interference. | Low to moderate reliability due to other wireless and environmental interference. |
| **Security** | High security through a physical transmission medium that is difficult to intercept or tamper with. | Wireless protocols can be less secure because the data is transmitted over the air and can be intercepted or jammed. |

| | | |
|---|---|---|
| **Cost** | Installation can be low to moderate – but the hardware itself is more straightforward. | Costs can be low to moderate at the software layer – but the internal hardware might be costly to maintain. |

Source: AEMC

**Existing business-to-business processes could be leveraged to activate real-time data**

Appendix F.2.1 above details the regulatory obligations placed on market participants today, including how customers and their authorised representatives can request and retailers must provide data. Behind those regulatory obligations are the metering data provision procedures, which currently detail the processes to provide customers with historical data. Market participants have online forms for customers and their authorised representatives to request historical data in a standard format and timeframe. Retailers and metering service providers can deliver historical data requests today without altering the smart meter because participants are required to ensure the meter can record and store the necessary data – the request can be fulfilled with a one-off backend inquiry.

In this section, we have detailed our final recommendation to be outcome-focused with regard to the methods for access to real-time data. This includes being technology-neutral and not regulating access to specific methods. Further consideration of how the enabling framework could practically activate real-time data to meet regulatory obligations is necessary. The objective should be to sufficiently detail the processes to provide customers with real-time data. The purpose would be to contribute to competition in data-driven services by minimising administrative burdens.

Real-time data from the smart meter may require one-off reconfiguring or reprogramming of the metering installation. These functions are currently covered by minimum service specification (f) advanced meter reconfiguration service.[280] At a minimum, the advanced meter reconfiguration allows for changing operational parameters, such as data streams and display presentation. We understand that the service can be applied more broadly, including:[281]

- Changing the hours of application of different registers (peak and off-peak).
- Installation of solar PV.
- Off-peak conversion (change from one off-peak Controlled Load tariff to another).
- Turn on/off off-peak registers.
- When a retailer needs to change tariff.

The current metering service specification (f) could be a starting point for activating real-time data for customers. These specifications have applicable roles and responsibilities, service

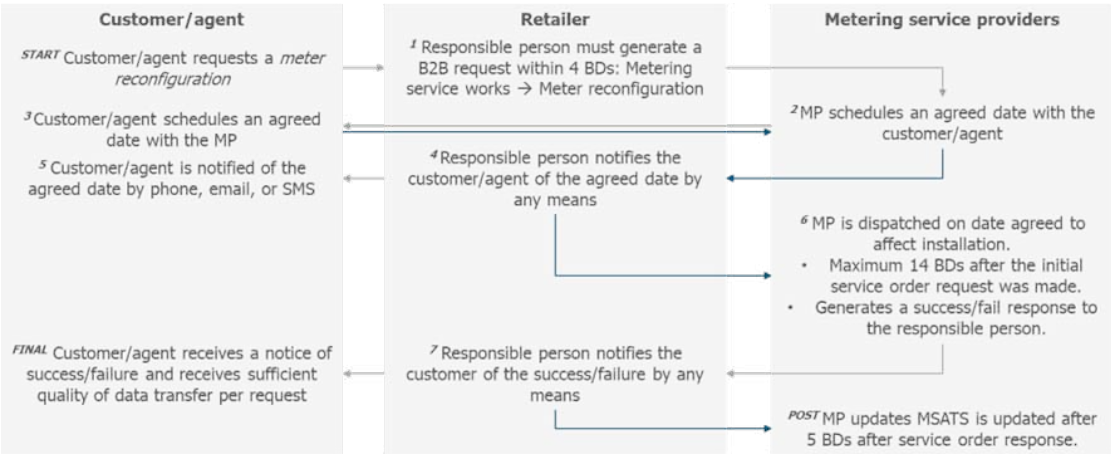
280 For more information, see NER Schedule 7.5.1, Table S7.5.1.1.

281 Metering parties must also maintain a permission provision log for the changes and access to the meter – which could be made available to customers digitally, free of charge, without undue delay, and/or on their request to support the user experience. For more information, see here: https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/b2b/2023/b2b-procedure-service-order-process-v38-clean.pdf?la=en.

order type, sub-type, and timeframe requirements (20 business days). The customer's retailer would be the initiator of this service order. Acting as an agent on behalf of the customer, the retailer could specify to the metering service provider the required configuration, using the Special Instructions field of the Service Order Request.

We recommend exploring whether this specification could provide a reasonable starting point for enabling access in any subsequent rule change process. The specification provides common understanding, consistency, and established standardised data access requests and provisioning procedures. If necessary, AEMO procedures could be adapted or refined to ensure customers can quickly, easily, and securely get the needed data. Using the current arrangements as a starting point, we have developed a potential process flow for a customer activating real-time data from the smart meter:

**Figure F.3: An existing process could potentially be leveraged to turn real-time data on**




AEMC

## F.5 Interoperability is necessary to support consumer access to data

We consider that interoperability is essential to support consumer access and data sharing. Interoperability refers to the ability of different systems, devices, applications, or products to connect, communicate, and exchange data without losing information or functionality. Interoperability requirements are critical across various sectors like banking, healthcare, transportation, and manufacturing. These requirements enhance efficiency, productivity, and decision-making — which are vital to real-time data access and sharing,

To enhance smart meter interoperability, we recommend a performance-oriented approach. Instead of mandating specific standards, the enabling framework should prioritise defining desired outcomes and functions. Industry participants should then adopt interoperability standards that can be reused from within the energy sector or are applicable across other sectors and services. This approach fosters flexibility, innovation, and reduced implementation costs.

Interoperability could be key to realising the full potential of real-time data access. It would ensure that customers and third-party providers can directly interact with smart meter functions regardless of the chosen smart meter or service provider, thereby promoting the adoption of new products and services without the need for proprietary protocol translations or constant regulatory adjustments (see Figure F.1).

### F.5.1 Previous stakeholder views on interoperable data access may differ in response to this final recommendation

Our Draft report tested stakeholder appetite for implementing common interoperability standards — in coordination with the ESB's interoperability Directions Paper.[282] Informing the Draft report was an understanding that the shared market protocol and file transfer protocol currently provides interoperability at the market and business server level to support the functioning of the NEM; however, communication between participant business servers and smart meters, or between business servers and consumer devices behind the meter, relies on protocol translation. Implementing an interoperable standard here could prevent several negative consequences, including:

- **Competition barriers:** New market participants may be discouraged from entering the market if they need to develop their own protocol translation capabilities.
- **Innovation stifling:** Developers of new consumer devices and applications may be reluctant to invest in new products if they are not confident that they can interoperate with the existing infrastructure.
- **Consumer choice reduced:** Consumers may be limited in the types of smart meters and devices that they can use if they are not interoperable.

There is a consensus among some stakeholders that interoperability is essential for CER and behind-the-meter technology integration, including smart meters; however, there is some disagreement on the specific standards that should be adopted.[283] Some stakeholders believe these standards are unnecessary, too costly, or difficult to implement.[284] These views were shared before the Commission came to a view on this enabling framework.

### F.5.2 Why does the Commission prefer a performance-oriented approach instead of specifying a standard?

Our final recommendation calls for an enabling framework with clear guidelines for consumer-driven innovation. Instead of specifying standards, a performance-oriented approach to interoperability could prepare participants for future standards while yielding near-term results. This would allow the use of established standards and methods to enhance interoperability without committing too soon. Focusing on performance empowers seamless integration once future standards are established. This preference has regard and seeks to align with:

282 ESB, Interoperability policy, Directions Paper, October 2022, p. 19

283 Submissions to the Draft report: Ausgrid, pp. 11-12; EDMI, p. 20; ECA, p. 13; Rheem and CET, p. 4; SATEC, p. 7; Secre, p. 11; SwitchDin, p. 3.

284 Submissions to the Draft report: EnergyAustralia, p. 6; Energy Queensland, p. 32; Intellihub, pp. 11-12; Origin, p. 8; Vector, p. 15.

- The reform direction set by the former ESB aims to enhance consumer access and utilisation of CER through a NEM-consistent methodology for the Australian Common Smart Inverter Profile (CSIP-Aus).
- The EU's Implementing Regulation and Data Act presents best practice examples of interoperable data-sharing directives.

**The direction of reform set by the former ESB**

The former ESB's interoperability reforms workstream aims to enable CER interoperability to enhance access and utilisation of various CER products and services by consumers, reduce complexity and time involved in managing equipment, provide greater flexibility to the energy system, and result in reduced costs and improved energy security for all consumers. Its priority was developing a NEM-consistent approach to implementing CSIP-Aus. CSIP-Aus would support the use of flexible export connections for small customers and lay the foundation for the broader integration of CER, including behind-the-meter interoperability and trader use cases.

The former ESB has identified a number of recommendations that would support a more efficient and consistent implementation of CSIP-Aus. The final advice for this workstream is expected to be published in late 2023. Our performance-oriented approach to interoperable data sharing would align with the goals and principles set out by the former EBS's reform direction by prioritising that the outcomes and functions are established in smart metering and they are complementary to current best practices. This should pave the way for the seamless integration of future standards — offering mutually reinforcing approaches to navigate the evolving energy ecosystem.

**The EU Implementing Regulation and EU Data Act**

The EU's Implementing Regulation and the EU Data Act offer advantages in prioritising interoperable outcomes and functions. Using these directions as best practice examples of data sharing, we consider that increasing interoperability as a matter of performance to share data in a potential enabling framework would promote consumer interests.

The EU's Implementing Regulation requires interoperability through a standardised interface or remote access to non-validated near-real-time metering and consumption data.[285] EU Member states must have due regard to using relevant available standards that enable interoperability on the data model level and the application layer. This is supported by a reference model to define common rules and procedures for the business, function, and information layers of interoperability in line with national practices.[286]

The EU Data Act's Articles 28 and 29 states that interoperability must be latent in device performance while allowing specific standards to be chosen and adopted with limited technical redundancy, by requiring interoperability in terms of the following:[287]

285 European Commission, Implementing Regulation, June 2023, p. 5.

286 European Commission, Implementing Regulation, June 2023, pp. 1, 16.

287 European Parliament, Data Act, 2022, pp. 56-58.

- **Data sets**: Content and usage restrictions (e.g., licences), data collection methodologies, data quality and uncertainty shall be sufficiently described to allow recipients to find, access, and use data.
- **Data structures:** Formats, vocabularies, classifications schemes, taxonomies and code lists shall be described in a publicly available and consistent manner.
- **Disclosure:** Describe the terms and conditions to enable automatic access and transmission of data between parties, continuously and in real-time – i.e., in a machine-readable format.
- **Performance oriented:** Interoperability specifications should be performance oriented towards achieving interoperability and portability between similar services – including guaranteeing functional equivalence where technically feasible.
- **Processing via the cloud:** The ability of different cloud systems to work together, to move data between cloud systems, and to move applications between cloud systems.
- **Technical means of access**: The method of access, such as the application programming interfaces, and their terms of use and quality of service need to be sufficiently described.

Further consideration of interoperability performance in a potential enabling framework for real-time data access should consider these elements of EU regulation, to deliver greater flexibility to the energy system at reduced cost all consumers.

## F.6 The Attorney-General's Department's recommendations for the Privacy framework will help alleviate privacy concerns

The Draft report recognised that, besides costs, consumers were most concerned about how their personal data will be used.[288] Unaddressed privacy concerns could undermine customers' willingness to accept an accelerated deployment and embrace new and innovative services of smart meters. In the Draft report, we recommended evaluating customers' concerns about data privacy. Stakeholders were invited to place the risk on a spectrum between severe/low consequences and high/low likelihood of occurring.  Based on this feedback there does not seem to be a residual risk in the existing privacy framework.

Given the recent personal data breaches across industries, the Attorney-General's Department was directed to review the Privacy framework.[289] The Attorney-General's Department has made 116 recommendation, including:[290]

- New data and informed consent requirements.
- Individual rights to remedies.
- Transparency of control and security mechanisms.
- Personal information definitions.
- Collection, usage, and disclosure choices.

288 SEC Newgate, AEMC Metering Review, Final report, p. 62.

289 For more information, see here: https://www.ag.gov.au/rights-and-protections/publications/privacy-act-review-report.

290 For a quick guide, see here: https://www.pwc.com.au/cyber/cyber-updates/quick-guide-privacy-act-reforms_021623.pdf

- Offshore data flow certifications.
- Exemptions processes.
- Enforcement powers.

The Commission does not believe adding further privacy protections in the NER or NERR for real-time data access is necessary at this time. We will monitor the implementation of the Attorney-General's Department's recommendations and engage with the Commonwealth on any gaps or overlaps, to ensure that the NER and NERR operate harmoniously with the privacy framework. This approach ensures that customer data privacy concerns are effectively addressed through the economy-wide privacy framework, while promoting sector-specific data sharing.

# G FIT-FOR-PURPOSE TESTING AND INSPECTION REGIME

The testing and inspection of metering installations plays a critical role in supporting the accuracy and reliability of information used to bill customers, settle markets and operate the system.

The Commission considers it appropriate to review the existing testing and inspection arrangements to minimise the complexity and cost of accelerated deployment, and support the 2030 universal take-up target. First, the value of maintaining a testing and inspection regime for legacy (type 5 and 6) meters scheduled for replacement needs to be reconsidered. Secondly, feedback from metering parties and AEMO has highlighted that the current arrangements for the inspection of smart (type 4 and 4A) meters may be leading to inefficient outcomes and need to be clarified.

This appendix outlines the Commission's final recommendations for testing and inspection requirements for legacy meters and smart meters, making them fit for purpose on an ongoing basis in the context of acceleration.

### BOX 8: RECOMMENDATIONS FOR A FIT-FOR-PURPOSE TESTING AND INSPECTION REGIME

To promote efficient testing and inspection of metering installations while supporting the accuracy and reliability of metering data, the Commission recommends:

1. Exempting legacy meters from regular testing and inspection during the acceleration period
2. Clarifying smart meter inspection requirements by:
   a. Obliging MCs to outline their inspection strategy in an AEMO-approved metering asset management strategy (MAMS)
   b. Requiring AEMO to develop a guideline for inspection outlining the information to be included in MAMS and its approach to approving MAMS

## G.1 Reduced testing and inspection requirements for legacy meters

### G.1.1 The Commission recommends a temporary exemption of testing and inspection requirements for legacy meters

The Commission recommends that legacy meters be exempted from testing and inspection requirements for five years during the acceleration period where the LMRPs are in place and implemented. If legacy meters are not replaced during this period as required under the LMRP, the testing and inspection requirements are to be reinstated after the acceleration period.

### G.1.2 Some stakeholders considered exemptions from testing and inspection requirements could lead to data inaccuracy

In the draft report, the Commission recommended the exemption from regular testing and inspection requirements for legacy meters, without stating a time limit. A few DNSPs, Origin Energy and AEMO support this draft recommendation, stating that they do not see value in testing and inspecting legacy meters as they are expected to be replaced under the LMRP. They also thought that testing and inspection may lead to unnecessary maintenance costs, and cause complexity in the development and implementation of the LMRP.[291]

Consumer groups including ECA, PIAC and ACOSS consider that malfunctioning meters identified via testing and/or inspection should be replaced in a timely manner. They are concerned that some customers with malfunctioning meters may have inaccurate bills, particularly if legacy meters under the LMRP are replaced based on geography instead of age.[292]

The Commission explored the following options for placing boundaries on the exemption to testing and inspection requirements with stakeholders:

1. Reinstating the testing and inspection requirements after each annual LMRP cycle.
2. Testing and inspection exemptions not applying to sites where attempted meter exchanges were not successful.
3. Exemptions applying for the five years of the acceleration period, with testing and inspection reinstated after 2030.

Stakeholders generally view Option 1 and Option 2 as adding more complexity to accelerated deployment. Option 2 was also deemed to be of limited value as unsuccessful meter exchanges are often due to an inability to access the meter. Therefore, metering parties would also be unable to access the meter for testing and inspection.

The Commission considers that Option 3 is likely to be the simplest and most effective solution to the concerns raised by stakeholders around testing and inspection requirements during the acceleration period.

### G.1.3 The exemption to testing and inspection requirements for legacy meters is intended to be temporary

The Commission's final recommendation is to reinstate regular testing and inspection requirements for legacy meters after the five-year acceleration period. This will provide a safeguard against inaccuracies and impairments to the metering installation at sites that retain a legacy meter, assuring the ongoing accuracy of customer bills.

The Commission agrees that without an exemption to the testing and inspection requirements, the implementation of the LMRPs would be challenging. Family failures of legacy meters would need to be replaced alongside those that are retired under the LMRP. Family failures could be of significant volume and geographically widespread. Metering

291 Submissions to draft report: Origin, p. 4; TasNetworks, p. 2; Energy Queensland, p. 4; AEMO, p. 4.

292 Submissions to draft report: PIAC, p. 16-17; ACOSS, p. 5; ECA, p. 5.

parties would likely find it challenging to appropriately prioritise and resource these meter replacements during the acceleration period.

Consumer groups are concerned that some legacy meters may not be replaced for more than 12 months and that customers will receive estimated billing during this time period. DNSPs can continue to test and inspect individual meters, such as a visual inspection at a quarterly meter read, where physical meter issues may be identified, or a test upon request by a customer. Individually identified failures such as these are required to be replaced within 15 business days from when the MC is notified of the malfunction under the recommended framework for malfunctions in this report. Further, unlike individual failures, there is typically less urgency in replacing family failures as only a portion of the entire family of metering devices will be outside of the strict accuracy limits in the NER.

The Commission notes meters that share a fuse at multi-occupancy sites will be replaced at the same time under the one-in-all-in approach outlined in this report. Under this approach, these meters will be replaced within 75 business days instead of up to one year under the LMRP timeframe.

### G.1.4 Implementation considerations

DNSPS, as MCs for legacy meters, would be exempted from the testing and inspection requirements in Tables S7.6.1.2 and S7.6.1.3 of the NER in relation to type 5 and 6 meters for the duration of the acceleration period, in NEM regions where an LMRP applies. The testing and inspection requirements would then reapply after the acceleration period.

## G.2 Clarifying smart meter inspection requirements

### G.2.1 We recommend new AEMO guidelines and an inspection objective in the NER

To clarify smart meter inspection requirements and enable efficient inspections, the Commission recommends that:

- MCs are required to set out their meter inspection practices in a metering asset management strategy (MAMS) to be approved by AEMO.
- AEMO develops a new guideline outlining the information that needs to be included in and their approach to approving MAMS. These guidelines could be further supported by a meter inspection objective and principles, which would be set out in the NER.

As well as clarifying inspection requirements, our recommendations would help to provide more options for efficient inspection strategies, such as the inclusion of remote monitoring using available smart meter technologies.

### G.2.2 Ambiguity in the NER is leading to different interpretations of the inspection requirements

MCs are responsible for both testing and inspecting meters under the NER. Testing consists of measuring the meter’s accuracy to confirm it is within an acceptable range. Inspection is a meter condition check, traditionally involving an on-site assessment of meter features such as direct readings, pulse counts, seals, physical connections, and signs of tampering.[293]

Schedule 7.6 of the NER sets out a default level of testing for each meter category in terms of a maximum period between tests, such as five years (Table S7.6.1.2). MCs can also submit an alternative testing practice in a MAMS, which is subject to AEMO's approval.[294] We understand MCs typically seek to use sample-based testing to minimise costs, in accordance with an approved MAMS.

Similarly, Table S7.6.1.3 of the NER sets out the maximum period between inspections for each meter type as shown below. The requirement for certain types is expressed as 'when meter is tested'.[295]

> **Table S7.6.1.3 Period Between Inspections**
>
> Unless the *Metering Coordinator* has developed an asset management strategy that meets the intent of this Schedule 7.6 and is approved by *AEMO*, the period between inspections must be in accordance with this Table S7.6.1.3.

| **Description** | **Metering Installation Type** | | | |
|---|---|---|---|---|
| | Type 1 | Type 2 | Type 3 | Type 4, 4A, 5 & 6 |
| *Metering installation* equipment inspection | 2.5 years | 12 months (2.5 years if *check metering* installed) | > 10 GWh: 2 years<br>2≤ GWh ≤ 10: 3 years<br><2 GWh: when *meter* is tested | When *meter* is tested. |

However, Table S7.6.1.2 (testing) also provides that:[296]

> The testing and inspection requirements must be in accordance with an asset management strategy. Guidelines for the development of the asset management strategy must be recorded in the *metrology procedure*.

Because the NER refer to inspection in multiple places, it is not clear whether 'when meter is tested' (that is, 'inspection upon testing') should apply if testing is sample-based, or if the intent is for MCs to submit an alternative inspection strategy in those cases.

In practice, MCs generally include inspection as well as testing in their MAMS. However, some MCs have not been able to gain approval for inspection upon testing as a complete inspection

293 NER Schedule 7.6; AEMO submission to directions paper, p. 7.
294 NER clause S7.6.1, Table S7.6.1.2.
295 NER clause S7.6.1, Table S7.6.1.3.
296 NER clause S7.6.1, Table S7.6.1.2.

strategy if testing is proposed to be sample-based.[297] MCs can potentially supplement physical inspections with remote monitoring, which is the use of the meter's measurements, communications facilities, and built-in alarms to continuously monitor its operation and flag potential problems. The Commission understands some MCs are already using remote monitoring,[298] either as part of or in addition to an AEMO-approved MAMS. However, AEMO and many MCs have different views on what level of remote monitoring is sufficient to satisfy the NER requirements, and what evidence should be used to show that a remote strategy is effective.

### G.2.3 Stakeholders consider unclear inspection requirements are leading to inefficient outcomes

AEMO and Intellihub both made submissions to the Review's consultation paper proposing changes to the meter testing and inspection requirements.[299] Intellihub considered that the existing inspection requirements were unclear,[300] and proposed the NER should permit inspection 'when meter is tested' for type 4 whole current meters.[301] AEMO, also citing lack of clarity, favoured MAMS submission and approval on a case-by-case basis, without any default inspection frequency in the NER.[302] The directions paper summarised the two differing proposals and called for feedback on their merits and implications, as well as the appropriate frequency for small customer meter inspections.

In their submissions to the directions paper, Vector and PLUS ES broadly supported Intellihub's proposal.[303] Green Metering suggested that different testing and inspection requirements could be appropriate for smart meters compared to legacy meters due to their capabilities.[304]

PLUS ES, Vector and Intellihub were concerned that the potential for different interpretations of the rule creates uncertainty. [305] PLUS ES considered AEMO's proposal (whereby MCs would need to submit a MAMS for approval) would 'reduce clarity for MP obligations, because the obligation is not known prior to AEMO's interpretation [that is, approval decision].'[306] MCs suggested that clarifying inspection requirements would make it easier for them to plan ahead and source investment, ensuring their businesses are sustainable and costs are kept down.[307]

MCs consider that the lack of clarity would likely lead to AEMO imposing time-based requirements such as a 10-yearly physical inspection of every meter – under either the status quo or AEMO's proposed changes. MCs view time-based inspection as onerous and inefficient

297 Intellihub submission to consultation paper, pp. 29-30.
298 Intellihub submission to consultation paper, p. 27; PLUS ES submission to directions paper, p. 33.
299 Submissions to consultation paper: AEMO, Appendix A, pp. 24-25; Intellihub, p. 32.
300 Intellihub submission to consultation paper, p. 27.
301 Intellihub submission to consultation paper, p. 31.
302 AEMO submission to consultation paper, Appendix A, pp. 24-25; AEMO submission to directions paper, pp. 5-6.
303 Submissions to directions paper: Vector, pp. 22-23; PLUS ES, p. 32.
304 Green Metering submission to directions paper, p. 12.
305 Submissions to directions paper: PLUS ES, p. 32; Vector p. 22; Intellihub submission to consultation paper, p. 31.
306 PLUS ES submission to directions paper, p. 32.
307 Intellihub submission to consultation paper, p. 31; PLUS ES submission to directions paper, p. 32.

for small customer meters as the costs outweigh the benefits.[308] Intellihub has estimated that 10-yearly inspections of whole current meters could contribute $10-15 per year to a typical customer's electricity bill.[309] Vector and Intellihub are not confident that the current requirements are applied consistently between legacy meters and smart meters.[310]

MCs argue that regular site visits for inspection are not necessary given the remote monitoring capabilities of type 4 meters. Remote monitoring can potentially detect faults and issues of concern more quickly than time-based inspections, using smart meter communications and systems.[311]

Intellihub proposed changes to the NER to clarify that the provision for inspecting meters when they are tested applies unless the MC chooses to submit an alternative strategy. This would mean the MC would not require AEMO's approval to use this inspection method as their main approach. This would imply that meters could be inspected on a sample basis. Intellihub also suggested that the NER could explicitly allow for MCs to supplement physical inspections (for example, inspection upon testing) with remote condition monitoring.[312] In their submission to the draft report, PLUS ES goes a step further and proposes that the NER requirements should be 'revised to replace scheduled testing and inspection with remote condition monitoring'.[313]

By contrast, AEMO proposed that all inspection strategies for whole current meters should be in accordance with a MAMS approved by AEMO.[314] AEMO considers that inspecting meters on a sample basis (which could be the outcome of Intellihub's proposal) would not be sufficient because inspection aims to detect meter condition faults, which do not necessarily correlate with meter characteristics such as make, model, or year of production. Further, they considered the requirement to submit MAMS would encourage MCs to innovate in their testing and inspection practices.[315]

AEMO says that it is open to approving MAMS with primarily remote inspection strategies, as long as it considers them well-justified. AEMO expects MCs to provide evidence for the effectiveness of remote monitoring before they can rely on it as an alternative to physical inspection. AEMO noted that smart meters are a relatively new technology in the NEM and that reliable testing and inspection practices are essential for maintaining the veracity of NEM data. In AEMO's view, a MAMS approval process is needed to ensure quality testing and inspection practices amongst competitive MCs.[316]

308 Submissions to directions paper: Intellihub, p. 13; Vector, p. 22.

309 Intellihub submission to consultation paper, p. 31.

310 Intellihub submission to consultation paper, p. 31; Vector submission to directions paper, p. 22.

311 Submissions to directions paper Intellihub, pp. 12-13; PLUS ES, p. 33.

312 Intellihub submission to consultation paper, p. 32.

313 PLUS ES submission to draft report, p. 34.

314 AEMO submission to consultation paper, Appendix A, pp. 24-25. AEMO also suggested introducing a default period of five years between inspections for type 4-6 meters other than whole current meters. In addition, they proposed simplifying the inspection period for all type 3 meters to be 2.5 years regardless of volume. Our recommendations are the same for all type 4-6 meters, and the Commission has not considered type 3 meters in this Review.

315 AEMO submission to directions paper, pp. 5-8.

316 AEMO submission to directions paper, pp. 5-8.

### G.2.4 MCs need better guidance when seeking approval for meter inspection strategies

Clear smart meter inspection requirements are needed to realise the full benefits of the accelerated deployment and promote efficient inspection practices, keeping costs down for consumers. The Commission's recommendations are designed to provide clarity and technical assurance along with flexibility, including potential options for MCs to use remote inspection strategies.

We recommend the following changes to the NER:

- Clarify that inspection must be in accordance with an approved asset management strategy, not 'when meter is tested'
- Require AEMO to develop a guideline specifying:
  - The information MCs should include in asset management strategies
  - The criteria AEMO will use to approve or refuse strategies
- Define a meter inspection objective
- Set high-level principles for AEMO to apply in developing the guideline.

The recommendations are designed to enable a cost-effective level of meter inspection that nevertheless supports confidence in the accuracy of NEM data. Disproportionate requirements would impose unnecessary costs on customers, while lax requirements would raise the risk of undetected meter faults and errors. Both risks would become more material with acceleration. The Commission considers the current lack of clarity (in both wording and intent) will lead to inefficient outcomes if not resolved, given stakeholders' conflicting viewpoints on the issue.

Our recommendations strengthen the requirement for MCs to submit MAMS, balancing flexibility with oversight. We intend that MAMS can propose remote monitoring strategies to fulfil inspection requirements. We acknowledge, as raised by AEMO, that inspection regimes not specified in the NER require engineering oversight, and that inspection upon testing may not be a sufficient strategy in itself. We consider that setting the frequency of physical inspections in the NER would not be appropriate (for small customer meters). For these reasons, the Commission recommends that meter inspection strategies should always be set out in a MAMS for approval by AEMO, with no default period between inspections.

Further, the Commission recommends that AEMO develops new guidelines to address MCs' concerns that MAMS approval may be unpredictable or inconsistent. The guidelines should outline AEMO's expectations on MCs submitting meter inspection strategies. This approach would allow more flexibility to accommodate changes in metering technology and its uses, compared to prescribing inspection requirements in the NER. We consider AEMO best placed to develop the guidelines due to their technical expertise in metering and their ongoing role in settlements.

The Commission is also proposing measures to ensure the inspection guidelines are balanced and reasonable. Some MCs are concerned that creating new guidelines would not change AEMO's assessment approach or level of discretion, so their current challenges with MAMS approval would continue. Introducing a meter inspection objective and principles in the NER could address this risk.

The objective would define the needs that inspection must meet and clarify that both physical and remote checks, where applicable, could be considered inspection under the NER. The principles would list factors that AEMO must consider when developing the guidelines. Cost-effectiveness would be key to mitigating the risk of inefficient requirements being set through the MAMS approval process. High-level principles referencing flexibility and innovation could also address some MCs' concerns about overly specific requirements hindering competition. We believe AEMO is well-placed to manage competing needs for clarity and flexibility in developing the guidelines, as they have also cited the importance of innovation.[317]

### G.2.5 How our recommendations would operate

#### Our recommendations would impose new obligations on MCs and AEMO

Our recommendations mean that all MCs would need to have a MAMS in place that has been approved by AEMO. The MAMS must address inspection of type 4-6 meters – in addition to inspection of other meter types and/or testing, where the MC prefers not to use the default NER requirements.[318] We expect any existing approved MAMS to remain valid. While our intent is to better enable the use of remote monitoring to fulfil inspection requirements where appropriate, MCs could still submit other inspection strategies, such as time-based.

AEMO would be required to develop and publish inspection guidelines explaining how MCs should demonstrate that their proposed inspection strategy meets the inspection objective. The guidelines would form part of the Metrology Procedure, and as such, would be developed in accordance with the Rules consultation procedures.[319] The Metrology Procedure and other AEMO materials already address testing and inspection to an extent, but guidance on inspection is limited.[320] The new inspection guidelines would need to address at least type 4-6 whole current meters in more detail. It would be open to AEMO to develop further guidelines on testing and/or inspection of other meter types.

We propose that the guidelines include the following main elements:

- A description of the information that MCs should provide to support their proposed strategy, whether remote, physical or combined, such as:
  - Details of the proposed inspection processes
  - Data collected from physical inspection or remote monitoring undertaken in the past
- A set of criteria that AEMO will use to determine whether to approve a MAMS

317 AEMO submission to directions paper, p. 6.

318 NER Table S7.6.1.2; Table S7.6.1.3.

319 NER clause 7.16.1(b); 7.16.3(a).

320 AEMO, *Metrology Procedure Part A v7.5*, p. 15, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/retail-and-metering/metrology-procedures-and-unmetered-loads.
AEMO, *Alternative Testing and Inspection Guidelines for Metering Installations in the NEM*, 2020, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/retail-and-metering/accreditation-and-registration. This document, published voluntarily, only applies to LVCT metering installations and not whole current meters (p. 5).
AEMO, *Whole Current Metering Installation Testing and Inspections* position paper, 2019, provided as Attachment B to AEMO's submission to the draft report, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services. This paper, published voluntarily to 'provide information about AEMO's position on asset management strategies for whole current meters' (p. 2) is brief and may not reflect AEMO's most recent views.

### The NER would present inspection requirements clearly and in one place

Both AEMO and Intellihub proposed removing the words 'and inspection' in NER Table S7.6.1.2 to clarify that this table applies to testing only.[321] The Commission agrees this change will provide clarity and Table S7.6.1.3 should fully address inspection requirements. (Legal drafting instructions in appendix I include this wording change.)

### An objective and principles for meter inspection would provide further clarity

The Commission considers the regulatory arrangements for inspection and the development of the guidelines would benefit from an inspection objective and principles set out in the NER. We consider this would further improve clarity and certainty for stakeholders. The objective and principles would be further developed in any subsequent rule change process.

Our initial proposed inspection objective is:

> That MCs have a physical inspection, remote monitoring, or combined strategy in place to reliably detect meter condition faults in a reasonable period, having regard to the costs and benefits to consumers.

Creating a clear inspection objective would reduce the ambiguity in inspection requirements by making it easier to determine whether an alternative inspection strategy 'meets the intent of this Schedule 7.6'.[322] Currently, the NER only provides a list of checks that inspection 'may include'.[323]

Principles could provide guidance regarding how guidelines should promote efficient inspections. We recommend that the principles address issues such as:

- The costs to MCs of complying with the guidelines, and implementing and sustaining inspection regimes, and the potential resulting costs for small customers
- Whether the information requirements are meaningful and proportionate to the risks that such information is intended to mitigate
- Whether the approval criteria are reasonable and proportionate to the purpose of inspection as described in the meter inspection objective
- The need for the guidelines to apply consistently and unambiguously to all relevant meter types and providers, while also enabling metering competition and innovation

The principles would describe, at a high level, matters that AEMO should consider in developing the guidelines and making MAMS approval decisions. The principles should not be technically detailed, as the aim is to allow for flexibility and innovation rather than locking in specific inspection methods or techniques. The approval criteria that AEMO would develop as part of the guidelines would be more specific and technical – reflecting the principles in the NER, but not necessarily corresponding one-to-one.

321 Submissions to consultation paper: AEMO, Appendix A, p. 24; Intellihub, p. 32.

322 NER clause S7.6.1, Table S7.6.1.3.

323 NER clause S7.6.2(f).

### The guidelines approach would provide flexibility in a changing NEM

Using guidelines, rather than prescribing the method or frequency of inspections in the NER, would allow fit-for-purpose inspection standards to be maintained in changing circumstances. AEMO would have the flexibility to update the guidelines in response to changes in meter capabilities, increased smart meter penetration, future reforms, or other factors. The Rules consultation procedures would ensure that MCs have input to any significant changes. For example, the *Unlocking CER benefits through flexible trading* rule change may introduce a new category of minor energy flow meters. These meters would likely need different or more flexible testing and inspection requirements.[324]

### There would be limited, if any, impact on legacy meters and large customer meters

Our recommended changes would apply to all type 4, 4A, 5 and 6 meters, including both whole current meters and CT (current transformer) metering installations. We have focused on problems that stakeholders identified relating to type 4 whole current meters. Impacts on other types would be limited. We consider it is appropriate to create consistent requirements in the NER for all type 4-6 meters, but AEMO could take technical differences into account in the guidelines and approval decisions.

The recommended changes would have limited, if any, effect on DNSPs' meter testing and inspection regimes. DNSPs, as MCs for type 5 and 6 meters outside Victoria, would need to have an approved MAMS in place addressing meter inspection. The Commission understands it is common practice for DNSPs to submit MAMS, and we expect existing MAMS to remain valid, so they should not need to materially change their inspection practices. We note also that legacy meters would be exempted from testing and inspection during the acceleration period (see appendix G.1). Victorian DNSPs, in their capacity as MCs for smart meters, would have the same options as MCs in the rest of the NEM.

Our recommendations would apply to type 4-6 CT metering installations. AEMO suggested setting a maximum period of five years between inspections for these installations.[325] However, the Commission considers it is more appropriate that MCs submit a MAMS for CT metering installations, to provide flexibility and consistency with whole current meters. AEMO may approach CT metering installations differently due to their technical differences.

Type 1-3 meter testing and inspection requirements would remain the same.[326]

324 AEMC, *Unlocking CER benefits through flexible trading* directions paper, pp. 48-49.

325 AEMO submission to consultation paper, Appendix A, p. 25.

326 The requirement that type 3 meters serving volumes less than two gigawatt-hours per annum could be inspected 'when meter is tested' would not change. However, MAMS for these meters would still be subject to AEMO's approval (NER Table S7.6.1.3). This Review has only considered – and consulted on – the small customer metering framework.

# H QUANTIFYING IMPACTS OF ACCELERATION

The draft report included an economic cost-benefit analysis of the accelerated deployment by independent consultants Oakley Greenwood.[327] This study showed that the accelerated deployment would have significant net benefits compared to the current 'new and replacement' framework.  A more detailed summary of the results and methodology used was provided in section 2.4 and appendix F of the draft report.[328]  This appendix outlines how the cost-benefit analysis fits in with the Commission's regulatory impact analysis (appendix H.1), the Commission's response to stakeholder feedback on the cost-benefit results, and the results of a new sensitivity analysis on the cost-benefit results.

Most stakeholders consider the cost-benefit analysis to be robust and agree it provides a strong basis for the 2030 target. Others have raised questions about the results. We address stakeholder feedback in appendix H.2 below.

For the final report, the Commission engaged Oakley Greenwood again to undertake a sensitivity analysis for potentially higher metering costs (appendix H.3).[329] Oakley Greenwood found that the net benefits of acceleration remain positive, although smaller, in the higher cost scenario. When tariff impacts and quicker restoration benefits are omitted, the net benefits are still positive or neutral for all states considered. We outline below the key findings of the sensitivity analysis (appendix H.3.1) and further details on the cost assumptions (appendix H.3.2).

## H.1 Our regulatory impact analysis methodology

The economic cost-benefit analysis forms part of the regulatory impact analysis that the Commission undertook to make its recommendations.

### H.1.1 We considered a range of policy options

The cost-benefit assessment compared a range of viable policy options that are within our statutory powers. Oakley Greenwood modelled the costs and benefits of the following options:

- A business-as-usual scenario where we do not make a recommendation to accelerate the smart meter deployment
- A recommendation for accelerated deployment reaching 100 per cent smart meters by 2030
- A recommendation for accelerated deployment reaching 100 per cent smart meters by 2032

327 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, 2022, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

328 AEMC, *Review of the regulatory framework for metering services* draft report, 2022.

329 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters: Sensitivity Analysis of Higher Meter, Installation and Other Costs*, 2023, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

### H.1.2 We assessed the benefits and costs of each policy option

The Commission's regulatory impact analysis for this Review used qualitative and quantitative methodologies to assess the benefits and costs of policy options. The depth of analysis was commensurate with the potential impacts.

In the cost-benefit analysis, Oakley Greenwood has only included those benefits for which quantitative modelling was feasible and proportionate to the potential impacts, although we have considered a broader range of costs and benefits in the Review as a whole. Outside of the quantitative cost-benefit assessment, we have identified the impacts on different stakeholders – in particular, consumers – and considered the costs and benefits for each.

The Commission focused on the types of impacts within the scope of the NEO and NERO. Based on this regulatory impact analysis, we evaluated the primary potential costs and benefits of policy options against the assessment criteria. Our recommendations consider the benefits of the options minus the costs. The Commission is satisfied that the recommendations are in the long-term interest of consumers.

## H.2 The Commission has considered stakeholder feedback on the cost-benefit analysis

Most stakeholders respond positively to the cost-benefit analysis in submissions to the draft report. AEMO describes the analysis as 'well-considered'[330] and the AEC considers it 'the most balanced assessment to date' because it demonstrated an economic case for accelerated deployment even if only a limited set of benefits were considered.[331] Other stakeholders such as Alinta Energy, Momentum, the CEC, SA Power Networks, Endeavour Energy and EDMI also express support for the conclusions of the cost-benefit analysis.[332] The following sections address the concerns raised by stakeholders in relation to the cost-benefit analysis.

### H.2.1 The accelerated deployment may have small, short-term cost impacts for customers

The cost-benefit analysis acknowledged that while net benefits accrue over time, there are short-term costs and these could be passed through to customers.[333] Some stakeholders are concerned about these impacts or more generally the allocation of costs and benefits to different parties.[334] Red and Lumo raise the 'apparent disconnect in the timings of the reforms, the establishment of the installation targets and the potential allocation of costs throughout the supply chain'[335] while ACOSS notes the importance of the way in which costs and benefits flow through to customers.[336]

330 AEMO submission to draft report, p. 3.

331 AEC submission to draft report, p. 1.

332 Submissions to draft report: Alinta Energy, p. 10; Momentum, p. 1; CEC, p. 1; SA Power Networks, p. 15; Endeavour Energy, p. 2; EDMI, p. 22.

333 AEMC, *Review of the regulatory framework for metering services* draft report, 2022, p. 135.

334 Submissions to draft report: ACOSS, pp. 3-4; Energy Queensland, p. 33; Alinta Energy, pp. 9-10; Red and Lumo, p. 33; Energy and Technical Regulation Division of SA DEM, pp. 2-3.

335 Red and Lumo submission to draft report, p. 33.

336 ACOSS submission to draft report, pp. 3-4.

The Commission acknowledges that the accelerated deployment is expected to have a small short-term cost impact on consumers. Overall, the cost-benefit analysis shows that bringing forward the deployment will achieve process efficiencies and economies of scale, increasing net benefits to consumers. That is, while some costs will be incurred earlier, they will be lower in the future and overall. We expect any impact on customers to be very small relative to the overall retail bill, and small compared to other potential drivers of bill increases. Further, the impacts are likely to depend on individual customers' circumstances, such as the amount of electricity they use, their daily load profile, and their DNSP's and retailer's tariff assignment policies. Retailers may further mitigate cost impacts by smearing costs over time or across their customer base.

### H.2.2 South Australia receives smaller net benefits for reasons including a slower BAU smart meter deployment

The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining (the Division) called for further explanation of the lower benefits in South Australia compared to New South Wales and Queensland.[337] SACOSS also noted this.[338] The net benefit is smaller for three main reasons (after accounting for South Australia's smaller population):

- The slower BAU smart meter take-up in SA (the reasons for which the Division also questions[339])
- The lower costs of legacy meter reading in SA (at present and under BAU)
- The relatively low network LRMC published by SA Power Networks, leading to smaller tariff benefits

In Oakley Greenwood's BAU scenario, South Australia reaches 100 per cent smart meter penetration in 2041 – later than the other states – due to the younger age profile of its legacy meter fleet. The BAU take-up rate takes into account new PV installations, new meter deployments arranged by the retailer,[340] and meter replacements due to failure or end-of-life. Oakley Greenwood's modelling assumes legacy meters reach their end of life after 30 years. In reality, meters may be replaced earlier or later since failures are not predictable, but we consider the modelled BAU take-up is reasonable overall.

The slower smart meter deployment under BAU means that South Australia experiences higher bring-forward costs compared to the other states, while the reduced installation costs due to geographical efficiencies are similar. This means that the installation efficiency does not *by itself* offset the capital bring-forward and implementation costs, as it does for New South Wales and Queensland. South Australia still sees an overall net benefit, although it is somewhat reduced due to the combined effect of the slower BAU deployment leading to higher bring-forward costs, lower meter reading costs, and lower tariff-related benefits.

337 Energy and Technical Regulation Division of SA Department for Energy and Mining submission to draft report, pp. 3-4.

338 SACOSS submission to draft report, p. 7.

339 Energy and Technical Regulation Division of SA Department for Energy and Mining submission to draft report, p. 3.

340 As defined in the NERR rule 3.

### H.2.3 Some feedback emphasised the potential impacts of remediation and remote areas

ActewAGL notes the cost-benefit analysis assumed a universal penetration of smart meters, without accounting for upgrades that cannot be completed due to remediation needs or other reasons, nor meters with remote communications disabled.[341] Similarly, AGL notes that meter reading costs would not be eliminated in remote areas with no connectivity.[342] We provide comments on this limitation of the cost-benefit analysis, and how the net benefits change if the smart meter deployment does not reach 100 per cent, in appendix D.

Telstra notes that some individual sites would have significant remediation needs meaning the benefits of smart meter installation would not outweigh the costs.[343] The regulatory framework allows customers the choice of whether and when to remediate, at their own expense, and this would remain the case under our recommendations. If state governments were to contemplate providing funding for remediation, they would take into account all relevant considerations.

AGL suggests there are 'significant costs associated with installing smart meters in remote areas' that the cost-benefit analysis did not specifically include.[344] The cost-benefit analysis does not separately model costs in urban and rural areas. AGL is also concerned the cost-benefit analysis may have overestimated the reduction in meter installation costs due to geographically organised deployment, as it did not account for factors such as customer churn.[345] We consider the meter installation costs are nevertheless appropriate as they are sourced from Victorian AMI deployment data, which reflects smeared costs over a wide area including a range of population densities. Appendix H.3 also outlines Oakley Greenwood's sensitivity analysis for higher metering costs in general, in which the absolute saving per meter is the same and the relative cost reduction is smaller.

### H.2.4 Some stakeholders view certain benefits were overestimated

SACOSS is concerned that the tariff-related benefits may not have been accurately estimated or may have been overstated, providing the following reasons:[346]

- The analysis assumed a high level of customer interest in solar soaker tariffs, without sufficient evidence.
- The analysis was based on a solar soaker network tariff and did not consider whether this would be reflected in retail tariffs, or the details of actual retail tariffs available.
- Households' responses to solar soaker and other TOU tariffs depend on many factors including family structure and housing circumstances.

The Commission acknowledges that benefits from the availability of TOU tariffs are difficult to predict and customers' responses would vary widely. Oakley Greenwood used reasonable assumptions and simplifications to estimate the benefits for each jurisdiction as a whole.

341 ActewAGL submission to draft report, p. 3.
342 AGL submission to draft report, p. 2.
343 Telstra submission to draft report, p. 7.
344 AGL submission to draft report, p. 2.
345 AGL submission to draft report, p.2.
346 SACOSS submission to draft report, p. 10.

Individual customers' behaviour is not directly relevant to an overall cost-benefit analysis, and the exact structures and levels of retail tariffs were not needed to estimate the type of economic benefits being considered. Finally, as stated in the draft report, the net benefits remain positive even if the tariff impacts (and quicker restoration benefits) are excluded completely.

AGL questions the inclusion of benefits from remote re-energisation and de-energisation (R/D), since Queensland and New South Wales regulations severely limit the use of these services.[347] We consider these costs should be included in the assessment of potential (but tangible) benefits as they could still be realised if jurisdictional requirements were to change. In any case, the net benefits for both Queensland and New South Wales remain positive if the remote R/D category is omitted.

### H.2.5 Other stakeholders view important benefits were omitted

By contrast, Intellihub considers the cost-benefit analysis to be conservative, but nevertheless useful, because it only considers a small number of 'traditional benefits'. Intellihub expects additional important benefits will emerge with a higher penetration of smart meters – such as new retail products, real-time CER visibility, and faster fault detection.[348] Similarly, Rheem and CET note the importance of increased PV hosting capacity, which the cost-benefit analysis did not quantify.[349]

The Commission reviewed these benefits comprehensively in the directions paper. However, the cost-benefit analysis excludes them to demonstrate that the economic case for acceleration is sound based on only firm, tangible benefits.

### H.2.6 The weighted average cost of capital remains appropriate despite changing interest rates

The Energy and Technical Regulation Division of the South Australian Department for Energy and Mining questions the use of a 5 per cent weighted average cost of capital (WACC) given the current rising interest rate environment.[350] Oakley Greenwood's original study showed that the benefits decline if the WACC is 7 per cent, but remain positive, indicating that the net benefits are robust to significant changes in interest rates. We recognise that future inflation and interest rates are uncertain and subject to change and we consider a 5 per cent real WACC remains appropriate over the time horizon considered.

### H.2.7 Some stakeholders call for an expanded scope or additional scenarios in the analysis

Some stakeholders suggest that the cost-benefit analysis should be extended in scope or that additional scenarios should be modelled, such as:

- ACOSS, PIAC and SACOSS in regard to an alternative DNSP-led industry structure or structures[351]

347 AGL submission to draft report, p. 2.

348 Intellihub submission to draft report, p. 3.

349 Rheem and CET submission to draft report, p. 1.

350 Energy and Technical Regulation Division of SA Department for Energy and Mining submission to draft report, p. 3.

351 Submissions to draft report: ACOSS, pp. 11-12; PIAC, pp. 10-11; SACOSS, p. 6.

- ACOSS and PIAC in regard to an earlier acceleration target of 2027[352]
- EnergyAustralia in regard to the costs incurred by MCs to complete the smart meter deployment by 2030 as opposed to a later date[353]
- EnergyAustralia in regard to the provision of basic PQD to distribution networks, taking into account format and communication method[354]

The Commission considers these extensions to the analysis would not be feasible given the data that is practically available, and they would not change the conclusion that acceleration is beneficial. The cost-benefit analysis shows greater net benefits for a 2030 completion compared to 2032, and we do not consider any earlier completion date would be viable to implement as explained in appendix A.

## H.3 We tested the sensitivity of the cost-benefit results to higher metering costs

Following the draft report, the Commission engaged Oakley Greenwood to undertake a sensitivity analysis of the impacts of higher metering costs on their findings. Metering cost assumptions are key input variables into the model. Multiple sources of information may be used to estimate the costs of smart metering, and the actual costs are set by retailer-MC contracts which vary with time, location, and the businesses involved. The Commission considered it would be prudent to test the results for a scenario where metering costs were significantly higher than those assumed in the draft report.

Continued engagements with industry stakeholders since the draft report highlighted that deployment costs faced by the metering industry could be higher than Oakley Greenwood's initial assumptions.

Oakley Greenwood's sensitivity analysis shows that the net benefits of acceleration are still positive, albeit reduced, in a higher metering cost scenario. Even if the contingent benefits are omitted, the net benefits remain positive or neutral for all states considered.

The results are explained in more detail below and in Oakley Greenwood's addendum to the cost-benefit analysis report.[355]

### H.3.1 Summary of results

Oakley Greenwood produced cost-benefit analysis results using an alternative set of metering cost assumptions that are overall higher than their initial assumptions. They found the overall benefits of an accelerated deployment continue to outweigh the costs (in NPV terms, 2022) for:

- New South Wales and the Australian Capital Territory ($166 million),
- Queensland ($160 million), and

352 Submissions to draft report: ACOSS, p. 10; PIAC, pp. 9-10.

353 EnergyAustralia submission to draft report, p. 5.

354 EnergyAustralia submission to draft report, p. 6.

355 Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, 2023, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

- South Australia ($27 million).

The results of the core and sensitivity cases are summarised in Table H.1 below.

**Table H.1: Results of the cost-benefit assessment sensitivity analysis for higher metering costs**

| NPV ($M, 2022) | STATE | NET BENEFITS (ALL) | NET BENEFITS (FIRM) | CONTINGENT BENEFITS |
|---|---|---|---|---|
| **Sensitivity** | **NSW and ACT** | 166 | 54 | 113 |
| | **QLD** | 160 | 33 | 128 |
| | **SA** | 27 | -1.5 | 29 |
| **Core cost-benefit assessment** | **NSW and ACT** | 256 | 143 | 113 |
| | **QLD** | 197 | 69 | 128 |
| | **SA** | 54 | 25 | 29 |

Source: Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, 2023.
Note: Firm benefits and costs include meter costs (capital, installation, back-office, and opex), meter reading, special reads, remote R/D, and acceleration program implementation. Contingent benefits include tariff impacts and quicker restoration. The contingent benefits are subtracted from the net benefits (all) to determine the net benefits (firm).

An important conclusion of the original CBA was that the case for accelerated deployment was still strong if 'contingent benefits' (tariff impacts and quicker restoration) were excluded. In the sensitivity, excluding these categories leads to net benefits of $54 million for NSW and $33 million for Queensland. There is a small loss of $1.5 million for South Australia. That is, accelerated deployment would essentially break even for South Australia, while still having a smaller net benefit for the other two states. The lower net benefits for South Australia are consistent with the original cost-benefit results.

The sensitivity analysis shows that even if metering costs are higher than we initially estimated, accelerating smart meter deployment is still in the long-term interest of consumers.

The higher installed meter costs in the sensitivity case affect the smart meter capital costs, the smart meter installation costs, and the bring-forward of these costs, as well as adding a new opex cost category.

- The benefit from reduced installation costs due to geographical efficiencies is lower for Queensland and New South Wales, and becomes a small cost rather than a benefit for South Australia. Although the efficiency saving on each meter installation is the same, the cost brought forward is larger.
  - For South Australia, this means the reduced installation cost due to geographic efficiencies almost offsets the cost of bringing installations forward. However, there are additional benefits from tariff impacts, meter reading, and so on.
- The previously unaccounted-for meter opex is significant, but similarly to the other costs used in this sensitivity, it is a conservative assumption.

The avoided meter reading, special reads, and remote R/D costs; the tariff impacts; the quicker restoration benefits; and the implementation costs are unchanged.

### H.3.2 Key assumptions

The sensitivity analysis uses meter cost estimates based on anecdotal information from MCs, whereas the original cost-benefit analysis used costs reported by Victorian DNSPs. In the alternative set of meter cost inputs:

- The combined capital and installation costs are approximately 5 per cent higher (under BAU).
- There is a back-office cost of approximately $100 per meter (consisting of scheduling, compliance, and communications) that was not previously considered.
- There is an operating expenditure of approximately $10 per meter per year that was previously assumed to be not material.

The total installed meter cost would be approximately 45 per cent higher on an NPV basis (assuming a 5 per cent discount rate and 15-year meter life), so these alternative assumptions are significantly higher than the core analysis.

We consider the original meter cost assumptions are nevertheless robustly based. They are informed by the actual costs incurred by DNSPs in Victoria's AMI (advanced metering infrastructure) deployment, meaning they are publicly documented and based on large sample sizes. The AER assessed and approved these costs (adjusting them where necessary) through the AMI Transition Charges process in 2016.[356] Oakley Greenwood adjusted the meter costs for inflation.

The installation cost for the accelerated deployment is based on United Energy's costs for 2014, when the installation rate was still high.[357] Oakley Greenwood reasoned that this cost was representative of a geographically organised, efficient smart meter deployment.

The installation cost under BAU is based on costs that the AER approved for Jemena for 2014, at which time Jemena's installation rate was slowing down because their smart meter deployment was almost complete.[358] Oakley Greenwood considered this to be a good representation of the current 'ad hoc' deployment cost as Jemena would have been completing installations that were missed on the first pass, so they would not be co-located.

The sensitivity analysis assumes that the cost reduction per meter would be the same absolute dollar amount as in the core analysis. This approach is conservative, and an assumption was necessary because the Victorian AMI deployment was the only source of empirical data on the costs of accelerated deployment. We have also assumed that the back-office cost remains the same during the BAU deployment and accelerated deployment. In reality this cost would very likely be reduced under acceleration due to economies of scale. All other assumptions remain the same as those used in the original cost-benefit analysis.

356 AER, *Final decision AMI Transition Charges Applications*, 2016, p. 4.

357 United Energy, *United Energy's 2017 AMI Transition Charge Application*, 2016, p. 16.

358 AER, *Final decision AMI Transition Charges Applications*, 2016, p. 32.

# I LEGAL DRAFTING INSTRUCTIONS FOR RECOMMENDATIONS

This appendix provides the drafting instructions (DI) for amending the NER and NERR to support the recommendations included in this review.

**Table I.1: Legal drafting instructions to the NER**

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| **Setting a target and mechanism to accelerate the deployment of smart meters across the NEM** | | |
| 1. | New provisions | **Legacy meter retirement plan (LMRP)**<br><br>Insert new provisions which set out the objectives, content and process for developing the LMRP. These provisions would include the following.<br><br><u>1. Objective of the LMRP</u><br><br>The objective of a LMRP would be to require Retailers and Metering Coordinators to replace all existing type 5 and type 6 metering installations with a type 4 meter by 30 June 2030 in a timely, cost effective, fair, and safe way.<br><br><u>2. The LMRP</u><br><br>DNSPs would be required to develop a LMRP for Retailers and metering parties to meet the above objective. The LMRP would include:<br><br>1. A schedule of NMIs to be replaced during the acceleration period and a plan of when each meter would be replaced – i.e., groupings of legacy metering installations to be retired and replaced each year of a five-year period (1 July 2025 to 30 June 2030);<br>2. any site information the relevant DNSP has for a NMI. For example, information regarding:<br>• the location, age, type and make of the metering installation and the building type (residential or business);<br>• issues that may hinder safe access;<br>• the likely configuration of the meter board;<br>• the present of shared fusing or site remediation issues.<br>3. a summary:<br>• |

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| | | • explaining how the LMRP proposal is consistent with the LMRP objective and principles; and<br>• describing how the DNSP has engaged with Retailers, metering parties and other relevant stakeholders in developing the proposed LMRP, the relevant concerns identified as a result of that engagement, and how the DNSP has sought to address those concerns.<br><u>3. LMRP principles</u><br>The order of retirement of legacy meter NMIs and their allocation to annual interim targets must take into account:<br>1. The annual interim targets for each financial year, which must be between approximately 15–25 per cent of the total number of meters to be replaced under the LMRP.<br>2. The overall efficiency of the acceleration program over the five-year period of the LMRP, including costs and cost savings for all relevant market participants. For example, in the interests of efficiency, legacy meters may be retired in geographic groupings, such as by postcode, zone substation or meter reading route.<br>3. The impacts on retailers and other related and affected parties. In particular, the ramping up and down of the deployment program must account for workforce planning and availability considerations for meter providers across the five-year period of the LMRP, including enabling efficient workforce planning for meter deployments in regional areas.<br><u>4. Consultation on the LMRP</u><br>After the DNSP has developed a draft LMRP, and before submitting it to the AER for approval, the DNSP would be required to:<br>1. provide relevant Retailers with information about the sites at which a legacy meter would need to be replaced;<br>2. consult with the Retailers and other relevant and affected parties;<br>3. provide the relevant parties with a minimum period of time to review the draft LMRP and provide comments; and<br>4. address any comments or submissions received from the relevant parties before submitting the LMRP to the AER for approval (see below).<br><u>5. AER approval of the LMRP</u><br>The relevant DNSPs must submit their LMRPs to the AER for approval |

| DI NO | PROVI-SION | RECOMMENDATION |
|---|---|---|
| | | by 31 March 2025. The AER's assessment of the proposed LMRP would be limited to whether the relevant DNSP has reasonably followed the required process – for example, whether the DNSP has considered stakeholder input and taken into account the LMRP objective and principles. The AER would not be required to undertake any consultation when conducting this assessment.<br><br>If a LMRP does not comply with the relevant requirements, the AER may notify the DNSP that it requires resubmission. The notice must be given as soon as practicable and must state why, and in what respects, the AER considers the LMRP to be non-compliant. A DNSP must, within 15 business days after receiving the notice, resubmit its LMRP in an amended form that complies with the relevant requirements set out in the notice. The AER may extend the timeframe for resubmission if it considers this necessary and appropriate in the circumstances. For example, if the AER considers that the LMRP is non-compliant because there has been insufficient consultation with the relevant parties, then the AER may agree to extend the 15 business day period to allow the DNSP time to properly consult on the LMRP prior to resubmission.<br><br><u>6. Amending an approved LMRP</u><br><br>A Retailer may apply to the relevant DNSP to amend an approved LMRP if the LMRP is affected by either:<br><br>• a material error (including a clerical mistake, miscalculation, misdescription, defect in form or is false or misleading information); or<br>• a material change in circumstances or event.<br><br>These materiality thresholds would apply to any LMRP amendments. Amendments will not be permitted unless one or both of these thresholds is satisfied.<br><br>• The DNSP may amend a LMRP if it appears to the DNSP that the plan is affected by a material error, material change of circumstances or 'event'. Where a Retailer seeks an amendment to account for a material change in circumstances or event, the Retailer's application to the DNSP should demonstrate:  an event that is beyond the reasonable control of the DNSP and/or Retailer has occurred, and the occurrence of that event could not reasonably have been foreseen by the DNSP and/or Retailer at the time of the development of the LMRP; and |

| DI NO | PROVI-SION | RECOMMENDATION |
|---|---|---|
| | | • a failure to adjust the LMRP schedule to reflect the consequences of the event would be likely to materially adversely affect the ability of the relevant retailer to comply with its obligations to meet the interim targets.<br>Where one or both of the materiality thresholds are met, the DNSP may amend the LMRP, and if it chooses to do so, may either accept the amendments proposed by the Retailer or may propose its own amendments to address the material error or material change in circumstances or event. In either case, the DNSP must undertake consultation regarding any proposed amendments, and must demonstrate that the proposed amendments are consistent with the LMRP objective and principles described above. Following such consultation, the amended LMRP would be required to be approved by the AER, consistent with the approach for new LMRPs.<br>The AER would be required to make its decision on whether to approve the amended LMRP within 20 business days. If approved, the AER must then re-publish the LMRP and notify stakeholders. |
| 2. | New provisions | **Complying with the LMRP**<br>Where a legacy meter has been scheduled for replacement in a LMRP, the Retailer must:<br>• use best endeavours to ensure it is replaced in accordance with the LMRP schedule; and<br>• meet the final target of universal penetration of smart metering installations by 2030 (subject to the Retailer being able to justify any failure to meet the target, based on a reasonable assessment of the circumstances).<br>If the Commission makes the rule as described in a subsequent rule change process, the Commission intends to seek AER agreement to jointly recommend that a civil penalty apply to non-compliance with the 2030 target.<br><u>1. Exceptions to the LMRP</u><br>Exceptions to complying in the LMRP would not be specified in the NER.<br>If a Retailer was unable to replace a meter in accordance with the LMRP, it would be responsible for reporting to the AER the reason for this and it would be left to the AER to determine if this was justifiable, based on a reasonable assessment of the circumstances.<br><u>2. Small customer switching</u> |

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| | | Where a small customer has switched during the acceleration period, the new retailer must arrange for the meter to be replaced before 30 June 2030 or six months after the small customer switches retailer, whichever is later.<br><br><u>3. Reporting on compliance with the LMRP</u><br><br>Retailers would be required to include in their retail market performance report their performance against the LMRP for each preceding year of the LMRP, including:<br><br>1. the total number of meters installed and percentage of the interim target achieved;<br>2. the total number of sites with issues preventing installation, including where installations were unable to be carried out;<br>3. the total number of meters installed that were not functioning as required by the end of the interim period;<br>4. in the interim period, the total number of sites gained within from customers transferring from another Retailer and the percentage of those metering installations replaced, and the total number of sites lost to other Retailers from customers transferring to another retailer;<br>5. the total sites to be visited in upcoming interim periods; and<br>6. an explanation of their performance against the interim and final targets, and an outline of the Retailer's plan to get back into compliance (if necessary). |
| 3. | New provision | Insert a new provision that prohibits Retailers from charging small customers any upfront costs or exit fees that relate to replacing a type 5 or 6 metering installation that is identified in a LMRP.<br><br>This prohibition would not apply to metering installations at new connections or where the meter replacement has resulted from the small customer installing equipment at the site, for example, solar panels or a battery. |
| **Reducing barriers to make deploying smart meters easier** | | |
| 4. | New provision | Retailers be required to record in MSATS the date of the notice(s) sent to a small customer as provided in drafting instruction number 22. |
| 5. | New provision | Metering Coordinators be required to record in MSATS details of any site defect identified during a site visit or meter installation attempt within 5 business days of discovering the site defect. The MC must record: |

<table>
<tr><th>DI NO</th><th>PROVISION</th><th>RECOMMENDATION</th></tr>
<tr><td></td><td></td><td><ul><li>if there is a site defect;</li><li>the nature of the defect.</li></ul></td></tr>
<tr><td>6.</td><td>New provision</td><td>One-in-all-in meter installation process<br>A new process would be inserted into the NER as follows:<ol><li>Where a Metering Coordinator (Original MC) has become aware that replacing a metering installation requires interrupting supply to another small customer or large customer, the Original MC must notify the relevant Retailer within 5 business days of becoming aware of the shared fusing.</li><li>Within 5 business days of being notified by the Original MC, the Retailer must inform the relevant DNSP of the shared fusing.</li><li>Within 20 business days of being notified by the Retailer, the DNSP must visit the site and determine all NMIs affected by the shared fusing. Once the DNSP has identified the affected NMIs, it must issue a notice to each relevant Retailer, which must include the name of the Original MC and the date on which the outage will take place when all affected meters must be replaced. This date must be between 25 and 45 business days after the notice has been issued by the DNSP to the affected Retailers.</li><li>Within 10 business days of receiving a notification from the DNSP, the Retailers will be required to appoint an MC (the Original MC or one of their choosing) and raise a service order for metering installation replacement(s). The date for the service order request must align with the date for the supply outage specified in the DNSP's notification (which will be at least 25 business days from the date the notification was received).</li><li>The DNSP and relevant parties will then be required to attend the site on that date and time specified to replace all affected meters. As indicated above, this must occur between 25 and 45 business days after the noticed referred to at paragraph 3 above is issued.</li></ol>Sites subject to the one-in-all-in meter installation process would be subject to the timeframes above and would be exempt from the timeframes identified in the LMRP (to the extent the relevant metering installations are identified in the LMRP).</td></tr>
<tr><td colspan="3">Improving the customer experience when they get a smart meter</td></tr>
<tr><td>7.</td><td>7.8.10</td><td>Create two categories of malfunctions for a metering installation at a small customer's premises:<br>1.</td></tr>
</table>

| DI NO | PROVISION | RECOMMENDATION |
| --- | --- | --- |
| | | 1. Individually identified malfunctions. The Metering Coordinator 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, then the timeframe is 30 business days after the Metering Coordinator has become aware of the need for that interruption, unless the site is subject to the one-in-all-in meter installation process outlined in drafting instruction number 6, in which case that framework will apply instead of this clause.<br>This category would cover situations such as:<br>• A meter reader reporting that a meter has been physically damaged or the display could no longer be read.<br>• 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.<br>2. Malfunctions identified through statistical testing (family failures). The Metering Coordinator must repair or replace meters that have been deemed to be malfunctioning through sample testing as soon as practicable but no later than 70 business days from when the Metering Coordinator has been notified, unless a site is subject to the multi-occupancy scenario outlined in drafting instruction number 6, in which case that framework will apply to that site instead of this clause.<br>Metering Coordinators would be able to seek an exemption from AEMO (as outlined in drafting instruction number 8 of this table) from complying with these timeframes. |
| 8. | 7.8.10 | Amend the exemption process for Metering Coordinators as follows:<br>• For individual meter malfunctions, the Metering Coordinator must use best endeavours to apply to AEMO for an exemption to the timeframes specified in clause 7.8.10 before the expiry of those timeframes. At the time of applying for an exemption, the Metering Coordinator must submit to AEMO a plan for how it proposes to address the reasons for being unable to install the meter.<br>• For family failure of meters, the Metering Coordinator must apply for an exemption to the timeframes specified in clause 7.8.10 |

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| | | before the expiry of those timeframes. At the time of applying for an exemption, the Metering Coordinator must submit to AEMO a plan for how it proposes to address the reasons for being unable to install the meters.<br>In assessing the exemption, AEMO must consider:<br>• the size of the family failure;<br>• the nature of the malfunction; and<br>• any previous exemptions that AEMO has granted. |
| **Introduction of arrangements for better access to power quality data** | | |
| 9. | 7.3.1 | Clause 7.3.1(a)(2) be amended to include the collection, processing, and delivery of Power Quality Data by Metering Coordinators, in addition to their existing obligations in relation to metering data.<br>To facilitate this, Chapter 7 of the NER will be amended to include a definition of Power Quality Data (as described below at row 13), and consequential amendments will be made to Chapter 7 to capture Power Quality Data. |
| 10. | 7.15.5 | Amend cl 7.15.5(e) to allow all Metering Coordinators (not limited to Metering Coordinators currently or previously appointed in respect of the relevant metering_installation, and in addition to retailers) to access and receive NMI Standing Data. |
| 11. | New provision | The Commission considers that a requirement for collection of Power Quality Data may not be appropriate for certain types of metering installation. This includes where metering installations do not have sufficient communications infrastructure or where the metering installation does not facilitate collection of Power Quality Data for some other reason._<br>Therefore, Metering Coordinators should be exempted from the requirements for collection, processing, retention and the delivery of Power Quality Data (as set out in the proposed amended cl 7.3.1(a)(2)), and therefore also exempted from the obligation to appoint a Metering Data Provider, in relation to these metering installation types. |
| 12. | New provision | A new provision be inserted requiring Metering Data Providers to provide Power Quality Data and relevant NMI Standing Data from a small customer metering installation to the Local Network Service Provider. At a high level, the Commission considers that the new provision could broadly mirror cl 7.10.3 in relation to metering data, and that an equivalent provision to cl 7.15.5(c) could be inserted in cl 7.15.5 that enables Local Network Service Providers to access Power |

| DI NO | PROVI-SION | RECOMMENDATION |
|---|---|---|
| | | Quality Data. This approach would mirror the approach adopted in relation to other how other data is provided / received under cl 7.10.3 and 7.15.5, respectively, in relation to metering data.<br><br>The Commission considers that it would be appropriate to incorporate Power Quality Data into the definition of metering data services, to ensure that obligations on Metering Data Providers in relation to, for example, the metering data services database and capability to provide metering data services are extended to Power Quality Data, to the extent necessary.<br><br>Metering Coordinators should be required to ensure that access to Power Quality Data and relevant NMI Standing Data provided under the new provisions is scheduled appropriately to ensure that congestion does not occur. The Commission considers that the requirement to do so could be achieved by amending or mirroring cl 7.15.5(b). |
| 13. | New provision | The Commission recommends inserting a new definition of 'Power Quality Data" in Chapter 7. This definition would include reference to the data points that comprise Power Quality Data, which at a basic level includes voltage, current, and active and reactive power (which could be represented as a phase angle). |
| 14. | 7.16 and 7.17 | Processes and procedures for sharing, and appropriate service levels for, 'basic' PQD will be defined in AEMO procedures rather than in the NER. To accommodate this, changes could be made to the rules providing for the development and amendment of service-level procedures for MDP services (see rule 7.16), and potentially, B2B transaction procedures (rule 7.17). |
| **Creating a fit-for-purpose testing and inspection regime for acceleration** | | |
| 15. | New provision | Metering Coordinators be exempted from the testing and inspection requirements in Tables S7.6.1.2 and S7.6.1.3 of the NER in relation to type 5 and 6 metering installations for the duration of the LMRP period. The testing and inspection requirements would then reapply after this period. |
| 16. | Table S7.6.1.2 | In clause S7.6.1, in Table S7.6.1.2, the description for 'Whole current Meter' would be removed and replaced with the following:<br><br>*The testing requirements must be in accordance with an asset management strategy.* |
| 17. | Table S7.6.1.3 | In clause S7.6.1, in Table S7.6.1.3, in the box for Type 4, 4A, 5 & 6 metering installations omit "When meter is tested" and substitute with the following: |

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| | | *In accordance with an approved Asset Management Strategy.* |
| 18. | New provision | Insert a new requirement on AEMO to develop guidelines for Asset Management Strategies that specify:<br>• The information Metering Coordinators must include in an Asset Management Strategy submitted to AEMO for approval. This would include, for example, evidence that the proposed methods are effective and detailed diagnosis and rectification procedures.<br>• The criteria AEMO will use when considering an Asset Management Strategy.<br>When developing the guidelines, AEMO would be required to comply with prescribed consultation requirements. The NER could also specify a meter inspection objective and high-level principles to be taken into account by AEMO in developing the guidelines. |

Table I.2: Legal drafting instructions to the NERR

| DI NO | PROVISION | RECOMMENDATION |
|---|---|---|
| **Setting a target and mechanism to accelerate the deployment of smart meters across the NEM** | | |
| 19. | New provision | A transitional provision be inserted that amends the notice requirements under rule 46(4) as set out below:<br>• Retailers would be required to include additional information in the notices, including:<br>• that the customer can request an estimate of what their historical bill would have been under the varied tariff, compared to the bill they received under the existing tariff (to the extent that the customer's smart meter data is available);<br>• how to understand, monitor and manage their usage (for example, through available apps or in-home displays).<br>• Retailers would be required to give at least 30 business days notice before the varied tariff is to apply to the customer. This would apply regardless of the reasons for the tariff change, and would include, for example, the underlying network tariff changing.<br>These amendments would only apply to small customers whose meters are replaced under an LMRP. Further, they would also cease to apply on 31 December 2030. |
| **Reducing barriers to make deploying smart meters easier** | | |

| DI NO | PROVI-SION | RECOMMENDATION |
|---|---|---|
| 20. | 59A | A small customer's right to opt-out of the deployment of new electricity meters under this clause be removed. |
| 21. | 59A | 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 more than 60 business days and not less than 4 business days before the proposed meter installation date. |
| 22. | New provision | The NERR be amended to specify the process for notification of site defects impacting installation as follows:<br>• Where a Metering Coordinator has been unable to install a meter at a small customer's premises due to a site defect, the relevant Retailer must notify the small customer of the site defect within 5 business days of being notified by the Metering Coordinator.<br>• If the Retailer has not received confirmation from the small customer that the site defect has been rectified within two months of issuing the first notice, the Retailer must send a follow-up notice to the small customer within one month of issuing the first notice to the customer.<br>• If the Retailer has not received confirmation from the customer that the site defect has been rectified within two months of issuing the second notice, the Retailer is required to confirm the status of remediation with the customer.<br>• If the Retailer receives confirmation from the customer that the site defect has been rectified, the Retailer is required to progress the metering installation in accordance with the timelines set out in clauses 7.8.10, 7.8.10A, 7.8.10B, 7.8.10C of the NER (as outlined in drafting instruction number 26).<br>Where a customer changes their Retailer during the notification process the incoming Retailer must complete all remaining steps of the notification process outlined above. |
| 23. | New provision | Where a Retailer will be unable to replace a metering installation because of a site defect, the Retailer will be required to issue a notice to the small customer, and potentially a follow-up notice, in accordance with the process described in drafting instruction number 21.<br>If the Retailer has not received confirmation from the small customer that the site defect has been rectified within 40 business days of issuing a second notice, then the Retailer will be required to report the status of the site remediation in the Retailer's next quarterly report |

| DI NO | PROVI-SION | RECOMMENDATION |
|---|---|---|
| | | under Part 12, Division 2 of the NERL and the AER Performance Reporting Procedures.<br><br>Where a site defect has not been rectified following two notices, the Retailer will not be required to complete the meter replacement, unless and until the site defect has been rectified. |
| **Improving the customer experience when they get a smart meter** | | |
| 24. | 59A | The information required to be provided in a notice to a small customer under rule 59A is expanded to include:<br>1. the reasons for the proposed new meter deployment;<br>2. how the customer can access their smart meter data;<br>3. the customer's rights and responsibilities regarding the metering installation;<br>4. the party the customer should contact to resolve issues, as well as dispute resolution options;<br>5. any changes to the customer's retail contract resulting from the metering installation, including tariff changes;<br>6. a summary of the services available to the small customer as a result of obtaining a smart meter; and<br>7. the proposed date range for installation of the new metering installation and supply outage.<br>Information regarding any upfront charges the customer will incur under their retail contract as a result of the new meter deployment, the retailer's contact details and contact details of interpreter services in community languages are already required to be provided in a notice issued under the current rule 59A. |
| 25. | 59C | A Retailer will be required to provide additional information in a notice to customers under rule 59C where an interruption is required to replace a meter with, or install, a type 4 or 4A meter. The purpose of requiring this additional information in a notice under rule 59C is to ensure that relevant information is provided to customers in all situations where they are being provided with a smart meter. In some cases, this will be part of a new meter deployment (as defined in the NERR, rule 3), in which case the information may be included in the Retailer's notice under rule 59A (see drafting instruction number 24). However, the Commission wishes to ensure that the same information is provided in situations where a notice is not issued under rule 59A (e.g. where the replacement is customer-initiated or the result of a failure). |

<table>
<tr><th>DI NO</th><th>PROVI-SION</th><th>RECOMMENDATION</th></tr>
<tr><td></td><td></td><td>This notice would be provided even if the Retailer and small customer agreed an interruption time.<br>The additional information would include:<ul><li>the reasons for the proposed new meter deployment;</li><li>the customer's rights and responsibilities regarding the interruption, including any potential costs that may be the responsibility of the small customer;</li><li>the party the customer should contact to resolve issues, as well as dispute resolution options;</li><li>any upfront charges the customer will incur under its retail contract as a result of the new meter deployment;</li><li>any changes to the customer's retail contract resulting from the metering installation, including tariff changes;</li><li>a summary of the services available to the small customer as a result of having a smart meter;</li><li>how the customer can access their smart meter data;</li><li>the proposed date range for installation of the new metering installation and supply outage;</li><li>the retailer's contact details; and</li><li>contact details of interpreter services in community languages.</li></ul>Retailers would need to provide the information notice at either:<ul><li>the same time as the notice under rule 59A (if required); or</li><li>not more than 60 business days and not less than 4 business days before the proposed metering installation date.</li></ul>To the extent this information is required to be provided by a Retailer under another provision of the NERR (for example, rule 59A), at a similar point in time, this notice may be taken as satisfying those obligations.<br>This notice would not need to be provided for new connections.</td></tr>
<tr><td>26.</td><td>New provision</td><td>A new clause is inserted that:<ol><li>enables small customers to request a smart meter from their Retailer for any reason; and</li><li>requires Retailers to install a smart meter on receipt of such a request, in accordance with clauses 7.8.10, 7.8.10A, 7.8.10B and 7.8.10C of the NER (as applicable).</li></ol></td></tr>
</table>

# ABBREVIATIONS AND DEFINED TERMS

| | |
|---|---|
| ACOSS | Australian Council of Social Service |
| ACT | Australian Capital Territory |
| AEC | Australian Energy Council |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AMI | Advanced metering infrastructure |
| BD | Business days |
| B2B | Business-to-business |
| CDR | Consumer data right |
| CE | Chief executive |
| CER | Consumer energy resources |
| Commission | See AEMC |
| CT | Current transformer |
| DNSP | Distribution network service provider |
| ECA | Energy Consumers Australia |
| ECS | Essential Services Commission |
| ENA | Energy Networks Australia |
| ETU | Electrical Trades Union |
| EU | European Union |
| EWO | Energy Water Ombudsman |
| FRMP | Financially responsible market participant |
| IEC | Information Exchange Committee |
| LMRP | Legacy meter replacement plan |
| LV | Low voltage |
| MAMS | Metering asset management strategy |
| 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 |
| NER | National Electricity Rules |
| NERL | National Energy Retail Law |
| NERO | National Energy Retail Objective |

| | |
|---|---|
| NERR | National Energy Retail Rules |
| NGL | National Gas Law |
| NGO | National Gas Objective |
| NGR | National Gas Rules |
| NMI | National meter identifier |
| NSW | New South Wales |
| OECD | Organisation for Economic Cooperation and Development |
| PIAC | Public Interest Advocacy Centre |
| PIN | Planned interruption notice |
| PQD | Power quality data |
| QLD | Queensland |
| SA | South Australia |
| SIRs | Service and installation rules |
| SO | Service order |
| SMS | Short message service |
| SPD | Service protection device |
| TIGS | Temporary isolation of group supply |
| TSS | Tariff structure statement |
| WC | Whole current |