AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Rule determination

National Electricity Amendment (Accelerating Smart Meter Deployment) Rule

National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule

Proponents

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SA Power Networks
Alinta Energy

28 November 2024

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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.

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Summary

1 The Australian Energy Market Commission (AEMC or Commission) has made final rules in response to the rule change requested by Intellihub, SA Power Networks and Alinta Energy (the proponents). The Commission has made a final electricity rule and a final retail rule.

2 The final rules promote a fast, efficient, and effective deployment of smart meters under an improved metering framework in the *National Electricity Rules* (NER) and *National Energy Retail Rules* (NERR).

3 The final rules will benefit consumers. The new framework created by the final rules increases the amount of information available to consumers about their energy use, allows consumers to better understand and manage their bills, and opens up access to new and better retail service options.

4 More broadly, it will benefit all energy stakeholders by enabling a more efficient, lower-cost, and lower-emissions energy system.

5 The final rules implement recommendations made as part of the *Review of the Regulatory Framework for Metering Services* (the Review), which was published by the Commission on 30 August 2023.[1] The rule change request was fast-tracked, reflecting the extensive consultation carried out during the Review. Our final rules are informed by stakeholder feedback received in response to the draft determination (published 4 April 2024), and the directions paper (published 15 August 2024).

6 The rules are implemented progressively, with the first schedule commencing on 5 December 2024 and the last schedule on 1 July 2026.

Smart meters provide the digital foundation for a modern, connected, and efficient energy system

7 The energy landscape is undergoing unprecedented change in response to market and technology developments, changing community expectations, and widespread government commitments to net zero. With the rapid uptake of CER, households and businesses will increasingly interact with the grid and energy markets.

8 Smart meters are an important tool to facilitate that interaction, and to support the cost-effective decarbonisation of the energy market. They also offer a range of benefits, particularly for consumers, but also for market participants and the system overall. Smart meters:

- help facilitate the efficient integration of Consumer Energy Resources (CER) — such as solar photovoltaic (solar PV) systems, home batteries and electric vehicles (EVs)
- provide consumers with visibility and control of their electricity consumption and costs, and more access to alternative pricing options
- create opportunities for greater data sharing - promoting competition and innovation, and support more targeted energy policies
- allow Distribution Network Service Providers (DNSPs) to improve their management of the electricity network.

9 The timely deployment of smart meters is a key enabler for market bodies' broader CER integration work program. This includes the Commission's recent *Unlocking CER benefits through*

1 AEMC, *Review of the Regulatory Framework for Metering Services*, https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

flexible trading rule,[2] and current *Integrating price-responsive resources into the National Electricity Market* (NEM) rule change, as well as delivery of key elements from the Energy Security Board's Consumer Energy Resources and the Transformation of the NEM report. [3] Energy Ministers have also recently committed to driving CER reforms through a National CER Roadmap and by establishing a CER Taskforce.

Reform to the current metering framework will get more smart meters installed faster

10 The current metering framework already provides a pathway for legacy meters to be replaced 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. However, it is 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.

We have made final rules to accelerate smart meter deployment to all NEM customers

11 Our final rules drive forward the reform agenda established in the Review, enabling the accelerated deployment of smart meters to consumers in a timely and cost-effective way. Faster replacement of legacy meters will enable consumers to access the benefits that smart meters can provide sooner.

12 The final rules reflect input provided by a wide group of committed stakeholders over numerous rounds of engagement. This includes feedback received in response to:

- the Review, which was delivered from 2020 to 2023
- the draft determination, which was published on 4 April 2024
- the directions paper, which was published on 15 August 2024.

13 This collaborative effort has been instrumental in identifying opportunities to shape priority reform actions and improve the current regulatory framework, to achieve better outcomes for customers.

The final rules will achieve universal uptake of smart meters in the NEM by 2030

14 The final rules includes two core reforms plus a set of four supporting reforms that together pave the way for universal uptake of smart meters by 2030.

2 AEMC, *Unlocking CER benefits through flexible trading*, https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading.

3 AEMC, *Integrating price-responsive resources into the NEM*, https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem.

Figure 1: Reforms delivered under the final rules

Core reforms to deliver the benefits that smart meters offer	
1 Accelerated deployment of smart meters	• opens new possibilities for innovative products and services, expanding customers' control of and choices around their energy use • lower costs to customers of meter reads and installations • provides for a modern, data-enabled energy system • underpins the cost-effective decarbonisation of the energy market • supports better integration of CER and a safer and more secure energy system.
2 Access to power quality data	• DNSPs can better manage their networks to reduce network costs for customers • saves energy, minimises network safety risks, and lifts hosting capacity.
Supporting reforms to enable the core reform program	
3 New customer safeguards	• protect customers from potential upfront charges and exit fees for new meters, and bill shock from unwanted retail tariff changes • builds social licence for the smart meter acceleration program.
4 Improving the customer experience	• helps maintain social license for the acceleration program • ensures that customers can access the full suite of benefits that smart meters provide.
5 Reducing installation barriers	• supports delivery efficiencies, and therefore cost savings, in the accelerated deployment of smart meters.
6 Improved meter testing & inspections	• helps minimise costs for industry and customers • supports a 2030 universal smart meter deployment target.

Source: AEMC

15 The Review's recommendations regarding real-time data access for consumers is being progressed through a separate rule change process. On 24 June 2024, we received a rule change request from Energy Consumers Australia (ECA) which recommends changes to improve real-time data access for consumers, in line with our Review recommendations. We initiated this rule change request on 10 October 2024 by publishing a consultation paper, and will consider these matters through this separate rule change process.

Our final rules contribute to the National Electricity Objective and the National Energy Retail Objective

16 We assessed the final electricity rule against the National Electricity Objective (NEO)[4] and the final retail rule against the National Energy Retail Objective (NERO)[5] using the five assessment criteria outlined below. We consider that the final rules will contribute to achieving these objectives. In addition to the NERO, the Commission is satisfied that the retail rule meets the consumer protections test. We also considered stakeholder feedback provided throughout the Review, and in response to the draft determination and directions paper. Our regulatory impact analysis established that the reform program has net benefits.

4 Section 7 of the National Electricity Law (NEL).

5 Section 13 of the National Energy Retail Law (NERL).

17 The final rules will:[6]

- **Improve outcomes for consumers** by providing earlier access to the benefits smart meters offer and improve the customer experience in the transition to smart meters through new customer safeguards and processes.
- **Support market efficiency** by enabling a faster, more efficient, and more cost-effective deployment of smart meters that promotes economies of scale and efficiency gains, and lowers associated metering costs.
- **Promote innovation and flexibility** by allowing DNSPs and retailers faster and better access to smart meter data, so they can develop and provide more innovative services and products for customers and better network management approaches.
- **Contribute to emissions reduction** by promoting the use of smart meter technology and data. Smart meters are essential infrastructure for the transition to renewable energy and a net zero energy system, and a critical enabler for the efficient integration of CER.
- **Address implementation considerations** by aligning industry capabilities, minimising disruptions, and maximising the potential for customers to realise the benefits from smart meters.

The final rules include transitional rules

18 The final rules both include transitional provisions, which are time-limited in nature.[7] This includes:

- the Legacy Meter Replacement Plan (LMRP) framework, which will only apply during the acceleration period from 2025 to 2031
- new customer safeguards prohibiting upfront costs and requiring a customer's explicit informed consent prior to retail tariff variations, which will only apply during the acceleration period
- provisions requiring the Australian Energy Market Operator (AEMO) to develop initial Asset Management Strategy Guidelines so AEMO can develop and consult on the guidelines before they come into effect
- requirements on the Australian Energy Regulator (AER) and AEMO to review, amend and publish procedures, guidelines and other documents to take into account the final rules.

19 Other rule changes made by the final rules, such as the power quality data (PQD) and installations amendments, make ongoing improvements to the metering regulatory framework, and therefore will continue beyond the duration of the acceleration period.

6 A detailed description of the draft rule can be found in Appendix D.

7 Transitional rules are rules that are time limited in nature (i.e. will be in effect for a certain period of time and will then cease to have any effect) or that are needed to commence before the main operating provisions of the rule to allow certain preparatory actions to occur.

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1 The Commission has made a final determination

The final determination is to make a final electricity rule and a final retail rule in response to a rule change request submitted by the proponents. The request seeks to accelerate the universal deployment of smart meters for customers across the National Electricity Market (NEM) and to unlock the benefits of smart meters sooner.

1.1 Our final rules will accelerate the deployment of smart meters and improve the metering framework

Our final rules will introduce two core reforms so that customers and the broader energy system can access the benefits that smart meters offer sooner.

In addition to these core reforms, our final rules introduce a range of supporting reforms. These address existing issues with the current metering framework and enable the core reforms.

Figure 1.1: The final determination includes core and supporting reforms to the metering framework

Core reforms to deliver the benefits that smart meters offer	
1 Accelerated deployment of smart meters	• opens new possibilities for innovative products and services, expanding customers' control of and choices around their energy use • lower costs to customers of meter reads and installations • provides for a modern, data-enabled energy system • underpins the cost-effective decarbonisation of the energy market • supports better integration of CER and a safer and more secure energy system.
2 Access to power quality data	• DNSPs can better manage their networks to reduce network costs for customers • saves energy, minimises network safety risks, and lifts hosting capacity.
Supporting reforms to enable the core reform program	
3 New customer safeguards	• protect customers from potential upfront charges and exit fees for new meters, and bill shock from unwanted retail tariff changes • builds social licence for the smart meter acceleration program.
4 Improving the customer experience	• helps maintain social license for the acceleration program • ensures that customers can access the full suite of benefits that smart meters provide.
5 Reducing installation barriers	• supports delivery efficiencies, and therefore cost savings, in the accelerated deployment of smart meters.
6 Improved meter testing & inspections	• helps minimise costs for industry and customers • supports a 2030 universal smart meter deployment target.

Source: AEMC

1.2 Our final rules are shaped by the Commission's Review findings

We conducted the Review to determine whether previous reforms introduced under the *Expanding competition in metering and related services rule 2015* had met expectations, and to determine whether changes were required to improve the efficiency and effectiveness of the regulatory framework for metering services.

We found that whilst the current metering market structure remained appropriate, the performance of the metering framework has not met the intentions of the original rule. A range of challenges were identified with the current metering framework:

- misaligned incentives between stakeholders to install smart meters, slowing their adoption
- process inefficiencies in smart meter deployments, leading to higher costs
- poor customer outcomes in the transition to smart meters, damaging customers' experiences with retailers and the energy system
- a lack of access to the data provided by smart meters, constraining the benefits that smart meters offer.

The Review made a series of recommendations to address these issues, which are reflected in the rule change request and our final determination.

Looking beyond the performance of the framework in the now, the Review also looked forward – to explore the future of metering services in a transitioning energy system.

Smart meters are the digital foundation of a modern, efficient, and connected NEM. As the energy transition progresses, households will become smarter and more autonomous over time, and will increasingly interact with the grid and energy markets. Smart meters are an important tool to facilitate that interaction, and support a cost-effective decarbonisation of the energy market.

The Review found that there would be significant benefits to energy consumers, and to the system overall, from more widespread adoption of smart meters. Many of the benefits, however, depend on achieving a much higher penetration of smart meters than that which currently exists. The Review found that the existing metering regulatory framework, left alone, would not deliver smart meters across the NEM fast enough to access these benefits and support the energy system's transition.

Given the clear case to get more smart meters on walls faster, the Review recommended a reform program to achieve universal smart meter penetration by 2030. This recommendation is reflected in the rule change request and our final determination.

1.3 Some Review recommendations will be progressed outside of this rule change process

The Review made a total of 21 recommendations. Not all recommendations were included in the rule change request submitted by the proponents and some therefore will be progressed separately to this rule change process.

This includes the Commission's recommendations regarding real-time data access, which were not included in this rule change request. On 24 June 2024 the Commission received a rule change request from Energy Consumers Australia (ECA) which recommends changes to improve real-time data access for consumers, in line with our recommendations from the Review.[8] We initiated this rule change request on 10 October 2024 by publishing a consultation paper, and will consider these matters throughout this separate rule change process.

8 *Real time data for consumers, https://www.aemc.gov.au/rule-changes/real-time-data-consumers.*

Figure 1.2: Some of the Review recommendations are not included in this rule change process

Review recommendations not captured within this final determination		
A Enabling access to real-time data	• supports customer control and choice • underpins innovation in products and services • maximises the value of CER.	Progressing through a separate rule change request.
B Support for customer site remediation	• potential regulatory change and customer financial support to remediate sites where necessary to enable a smart meter installation.	To be considered by governments.

Source: AEMC

1.4 Our final determination was shaped by the extensive stakeholder consultation

Our final determination reflects extensive feedback provided by a wide group of stakeholders during both the Review and this rule change process.

The Review was conducted across three years from December 2020 to August 2023. Stakeholders from across the energy landscape contributed to the Review, including consumer and industry representatives.

Industry participants widely agreed that the current approach to legacy meter replacement will not lead to smart meters being deployed fast enough to support the transition to the future energy system.

The proponents also indicated their support for the Review recommendations and considered that they should be progressed as a matter of urgency. This is significant, noting the proponents are all different industry stakeholders, but jointly submitted the rule change request.

The Commission decided to fast-track this rule change request, given:

- it is consistent with relevant recommendations made by the Commission in the Review
- we consider that there was adequate consultation with the public during that Review on the relevant recommendations.

We published a draft determination on 4 April 2024 to seek stakeholder feedback on the draft rules. We received significant interest from a broad range of stakeholders, including at our public forum and through submissions to the draft determination.

We also published a directions paper on 15 August 2024. This paper sought stakeholder feedback on proposed enhanced consumer safeguards for the accelerated smart meter rollout, in addition to those identified in the draft determination. These additional safeguards were proposed in response to stakeholder concerns regarding the impact of retail tariff variations following a smart meter deployment, and feedback from some stakeholders that the consumer safeguards proposed in our draft determination should be enhanced. Stakeholders provided feedback on our directions paper through a public forum and submissions to the directions paper.

The feedback we have received throughout this rule change process has been important in informing our position for the final rule determination. We thank stakeholders for their valuable contributions and engagement throughout both the Review and rule change processes.

1.5 Cost-benefit analysis demonstrates the reform program has net benefits

The Commission undertook regulatory impact analysis to make its final determination, which draws upon the cost-benefit analysis conducted by Oakley Greenwood for the Review.[9] We found that the final rules would result in greater overall benefits than costs in the NEM regions, excluding Victoria and Tasmania (which already have acceleration programs in place).[10]

Key benefits include achieving significant economies of scale from installing meters by geographical area, avoided manual meter reading costs, and faster restoration and more efficient identification of the location and source of power supply after unplanned outages.

1.6 Our final determination supports the transition to renewable energy and emissions reduction

The final determination recognises that the energy landscape is in a period of unprecedented change. These changes are in response to developments in the market and in technology, changing community expectations, and the shift to a cleaner energy system.

Smart meters are critical infrastructure for transitioning the NEM to a renewable energy system and achieving a net zero emissions reduction target.

Operating the NEM is likely to become more complex and challenging with a higher penetration of variable renewable energy. Smart meter data is necessary for an orderly transition to net zero because it empowers stakeholders – consumers, network operators, market participants, and service providers – with the information they need to take full advantage of the benefits of CER.

The final determination is integral to work currently being led by the Commission and other stakeholders on CER integration. This includes the Commission's current review *The Pricing Review: Electricity pricing for a consumer driven future*, the Commission's recent *Unlocking CER benefits through flexible trading rule*,[11] and the current *Integrating price-responsive resources into the NEM*[12] and *Real-time data for consumers* [13] rule changes, as well as key elements from the Energy Security Board's Consumer Energy Resources and the Transformation of the NEM report.[14]

The final determination is also significant noting Energy Ministers' commitment to progress a CER Roadmap and the establishment of an expert CER Taskforce. This Taskforce will progress CER reforms and further define and drive the CER integration actions needed, and the strategies developed by the Commonwealth, State and Territory jurisdictions to implement CER.[15]

9 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, September 2022, https://www.aemc.gov.au/sites/default/files/2023-08/oakley_greenwood_cba_report_-_september_2022.pdf; Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, August 2023, https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_addendum_to_oakley_greenwood_cba_-_higher_meter_cost_sensitivity_-_august_2023.pdf.

10 The cost-benefit analysis conducted did not consider Victoria and Tasmania in its analysis. Victoria has previously completed a universal rollout of smart meters. Tasmania has also independently initiated an accelerated smart meter deployment program.

11 AEMC, *Unlocking CER benefits through flexible trading*, https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading.

12 AEMC, *Integrating price-responsive resources into the NEM*, https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem.

13 AEMC, *Real-time data for Consumers*, https://www.aemc.gov.au/rule-changes/real-time-data-consumers.

14 Energy Security Board, *Consumer Energy Resources and the Transformation of the NEM report*, 7 February 2024, https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/consumer-energy-resources-and-transformation-of-nem.

15 Energy and Climate Change Ministerial Council, Meeting Communique, 24 November 2023, https://www.energy.gov.au/sites/default/files/2023-11/ECMC%20Communique_24%20Nov%202023.docx.

2 The rule will contribute to the energy objectives

2.1 The Commission must act in the long-term interests of energy consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[16]

For this rule change, the relevant energy objectives are the NEO and NERO.

The NEO is:[17]

> 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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The NERO is: [18]

> 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—
>
> (a) price, safety, reliability and security of supply of energy; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO and NERO.[19]

2.2 We must also take the following factors into account to decide whether to make a change to the rules

2.2.1 We have considered the consumer protections test for this rule change

In addition to applying the NERO, the Commission must, where relevant, satisfy itself that the retail rule is "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers" (the consumer protections test).[20] Where the consumer protections test is relevant in making a rule, the Commission must be satisfied that both the NERO test and the consumer protections test

16 Section 88(1) of the NEL and section 236(1) of the NERL.

17 Section 7 of the NEL.

18 Section 13 of the NERL.

19 Section 32A(5) of the NEL and section 224A(5) of the NERL.

20 Section 236(2)(b) of the NERL.

have been met.[21] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made (noting that there may be some overlap in the application of the two tests).

The Commission is satisfied that the final retail rule meets the consumer protections test for the reasons set out in section 2.3 below.

2.2.2 We have considered how the rule would apply in the Northern Territory

The final electricity rule will apply in the Northern Territory, as it amends provisions in the NER Chapter 10, which does apply in the Northern Territory. However, these amendments will have no practical effect in the Northern Territory.

See Appendix C for more detail on the legal requirements for our decision.

2.3 How we have applied the legal framework to our decision

The Commission must consider how to improve the regulatory framework for metering services and enable an efficient and effective deployment of smart meters against the legal framework.

We identified the following criteria to assess whether the proposed rule change, no change to the rules (business-as-usual), or other viable, rule-based options are likely to better contribute to achieving the NEO and NERO:

- **Consumer outcomes:** do the proposed changes to the metering framework provide consumers earlier access to the benefits that smart meters offer? Do they improve consumer information and protections throughout the transition to smart meters?
- **Market efficiency:** do the proposed changes enable a more efficient deployment of smart meters than under the current framework? Do they reduce regulatory and practical barriers to speeding up deployment, and give stakeholders better access to smart meter data?
- **Innovation and flexibility:** do the proposed changes to give stakeholders earlier access to smart meter data support more innovative services and products for consumers, and more innovative management of the energy network?
- **Emissions reduction:** do the proposed changes support achieving government targets for reducing Australia's greenhouse gas emissions? Do they also align with broader reforms on CER integration?
- **Implementation considerations:** do the proposed changes align with industry capabilities and ensure universal smart meter deployment can be achieved by 2030?

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request, for impacts within the scope of the NEO and NERO.

The Commission has undertaken regulatory impact analysis to evaluate the impacts of the various policy options against the assessment criteria. Appendix B outlines the methodology of the regulatory impact analysis.

The rest of this chapter explains why the final rules best promote the long-term interest of consumers when compared to other options and assessed against the criteria.

Relevant sections of the final determination provide additional detail on how the objectives are achieved.

21 That is, the legal tests set out on sections 236(1) and (2)(b) of the NERL.

2.3.1 A faster deployment of smart meters will improve outcomes for consumers

The final rules improve outcomes for consumers by enabling a faster deployment of smart meters, which provides earlier access to the benefits that smart meters offer. This includes access to better information, better visibility of low-priced periods, and greater choice of retail offers.

The final rules also include measures to improve the customer experience during metering upgrades and new customer safeguards, including:

- enhanced information requirements for customers before smart meter upgrades
- giving customers the right to request and receive a smart meter for any reason
- more coordinated processes to upgrade meters on a shared fuse and replace malfunctioning meters
- safeguards to protect consumers against upfront charges
- safeguards requiring a retailer to seek a customer's explicit informed consent for any retail tariff change following a smart meter upgrade, for two years following a smart meter upgrade
- safeguards requiring designated retailers to offer customers with a smart meter a flat tariff offer (noting that jurisdictions would need to apply this rule through a local instrument).

2.3.2 The improvements to the metering framework will enhance market efficiency

The final rules support improved market efficiency. An accelerated deployment of smart meters will lead to economies of scale and efficiency gains, which will in turn lower individual meter installation costs. This is supported by the new Legacy Meter Replacement Plan (LMRP) mechanism which facilitates an efficient deployment strategy. Oakley Greenwood's analysis shows that full deployment by 2030 creates lower costs overall for consumers.

The final rules also support market efficiency by reducing barriers, regulatory burdens, transaction costs, and information asymmetry between consumers and market participants. For example:

- removing customer opt-out provisions for a new smart meter deployment and establishing new tracking processes for defects at metering installations, will make it easier to deploy smart meters
- reducing the number of customer notices ahead of smart meter upgrades, and improving the information they contain, reduces administrative burdens and costs, and enables greater flexibility, planning and coordination for industry stakeholders
- new arrangements which give DNSPs' better access to basic power quality data (PQD) help overcome the commercial barriers, including high costs, DNSPs face currently to access the data
- temporary exemptions for metering coordinators (MCs) from testing and inspecting legacy meters during the accelerated deployment allows industry to focus more resources on the accelerated deployment.

2.3.3 Smart meters support increased innovation and flexibility

The final rules promote innovation and flexibility by accelerating the deployment of smart meters. This in turn provides the data necessary for customers to make informed choices, and for retailers and service providers to develop and offer more innovative products.

A faster deployment of smart meters also enables DNSPs to manage their networks through more innovative methods. With increased visibility of PQD, DNSPs can develop new methods for getting more out of their existing assets, minimising new expenditure, and increasing CER hosting capacity.

2.3.4 Smart meters help achieve emissions reductions targets and integrate CER across the NEM

The final rules contribute to emission reductions targets as smart meters support the integration of low or zero emissions technologies.

Smart meters also support increased integration of CER such as solar PV, battery energy storage systems, and EVs. Networks can use smart meter data to maximise solar PV hosting capacity and minimise EV augmentation expenditure requirements.

Smart meters facilitate a more flexible demand response in the wholesale market. In turn, smart meters will support the NEM to increasingly integrate variable renewable energy.

2.3.5 These changes can be implemented effectively

The implementation approach in the final rules aligns with industry capabilities, minimises disruptions, and maximises the potential for customers to realise benefits.

The final rules also support implementation considerations through establishing various processes and changes that reduce some of the practical barriers to smart meter installation.

The Commissions' final rules consider the impact on and variability of costs, the timing of benefits, and complexities in regulatory arrangements. Throughout the Review there was extensive consultation on whether a 2030 target is achievable. The Commission has had regard to the potential financial impacts for different industry participants across the electricity value chain and customers. The Commission is satisfied that the cost impacts of an accelerated deployment are likely to be relatively modest.

3 How our rules will operate

3.1 Accelerating the deployment of smart meters across the NEM

Box 1: Final determination

1 Accelerated deployment of smart meters	• opens new possibilities for innovative products and services, expanding customers' control of and choices around their energy use • lower costs to customers of meter reads and installations • provides for a modern, data-enabled energy system • underpins the cost-effective decarbonisation of the energy market • supports better integration of CER and a safer and more secure energy system.

Smart meters are an important tool to support households in getting the most out of the energy transition. Accelerating the deployment of smart meters across the NEM will allow customers to access the range of benefits that smart meters offer sooner, and will underpin the cost-effective decarbonisation of the energy market.

The final rules:

- sets a clear target in the NER for the accelerated deployment of smart meters between 2025–2030
- establishes a new Legacy Meter Replacement Plan (LMRP) mechanism, which will facilitate industry collaboration to deliver smart meters to all NEM customers by 2030
- introduces new obligations on retailers to meet the 2030 target and a compliance monitoring role for the AER.

3.1.1 The final rules target the universal uptake of smart meters by 2030

The 2030 target will benefit customers and the broader energy system

The Review identified the benefits that accrue from an accelerated deployment of smart meters. Cost-benefit analysis demonstrated that this reform initiative will deliver net benefits to NEM customers — even under conservative assumptions where when the benefits included are narrowed, and when costs are higher than expected.

There is a clear case to accelerate the deployment of smart meters in the NEM, as articulated in the Review. Our final rules put this ambition into action, with accelerated deployment of smart meters being one of the two core reforms in the final rules.

The final rules introduce a reform program targeting universal take up of smart meters by 2030

Under the final rules, new regulatory arrangements will require retailers and MCs to replace all existing Type 5 and Type 6 metering installations ('legacy' meters) with a Type 4 ('smart' meter) meter by 1 December 2030.[22] In response to stakeholder feedback to the draft determination, the definition of legacy meters excludes type 5 meters that are capable of remote acquisition.[23]

22 The acceleration period timeline was shifted by 5 months compared to the draft rule given the extension to this final determination.

23 Submissions to the draft determination: Jemena, p. 1. See the definition of 'Legacy Meter' in the Electricity and Retail Amending Rules. Refinements to this definition will ensure that the accelerated deployment does not prematurely replace Victorian Type 5 meters with remote capabilities.

In response to the draft determination, a broad range of stakeholder submissions were supportive of our proposal to accelerate the deployment of smart meters across the NEM by 2030. Submissions recognised the importance of smart meters in supporting the future energy system.

In the Review, we found that 2030 is the earliest feasible target date.[24] Consistent with the Review and the draft determination, we maintain this position in our final determination. In submissions to the draft determination, some retailers considered that the 2030 target will lead to significant resource constraints,[25] whilst other stakeholders considered that 2030 is achievable.[26] No new information or arguments have been provided by these submissions that would cause us to change our view. Importantly, Oakley Greenwood's analysis showed delaying the target date for universal penetration beyond 2030 is likely to lead to a reduction in benefits that is not offset by the reduced capital costs.

We acknowledge that there are barriers that may prevent a 100 per cent smart meter uptake by 2030 in practice. For example, site remediation may be a barrier to smart meter installations, with some customers being unwilling or unable to pay required remediation costs. Site remediation is currently the responsibility of the customer and beyond the scope of the energy laws and rules. A customer cannot be compelled to remediate their site.

Noting these barriers, the Review recommended that governments consider financial support options to encourage remediation, particularly for vulnerable customers. The Commission continues to stand by this recommendation. The final determination includes rule changes to encourage customer remediation, where possible (see section 3.5 below).

Independent cost–benefit analysis supports the need for an accelerated deployment program

As part of the Review, we engaged Oakley Greenwood as independent economic advisors to undertake a cost–benefit analysis (CBA) for accelerating the deployment of smart meters across the NEM (excluding Victoria and Tasmania).[27] 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 CBA found that the program has net benefits overall, and for each jurisdiction.

Oakley Greenwood conducted sensitivity testing of these results and found that:

- the net positive result remains even if only a very limited set of highly achievable 'non-contingent' benefits are included
- net benefits remain positive even under higher metering cost scenarios.

3.1.2 The final electricity rule requires industry to collaborate on planning and delivery

A new LMRP mechanism will coordinate industry to efficiently deliver against the 2030 target

A significant amount of planning will be required to meet the 2030 target efficiently and at lowest cost to customers. The final electricity rule introduces a new regulatory mechanism where DNSPs work with retailers, MCs, and other stakeholders to develop a Legacy Meter Replacement Plan (LMRP) showing which legacy meters will be replaced, and when.

24 AEMC, *Review of the regulatory framework for metering services,* Final Report, 30 August 2023 (Review final report), pp. 28–32.

25 Submissions to draft determination: AEC (p. 1); AGL (p. 4); EnergyAustralia (pp. 1–2); SNAPI (p. 1).

26 Submissions to draft determination: Ausgrid (p. 1); Clean Energy Council (p. 1); ENA(p. 1); Energy Queensland (p. 1); Evoenergy (p. 1); Intellihub (p. 2); Origin (p. 1); PIAC (pp. 3–4); Plus ES (p. 3); SA Power Networks (p. 1).

27 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, September 2022, https://www.aemc.gov.au/sites/default/files/2023-08/oakley_greenwood_cba_report_-_september_2022.pdf; Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, August 2023, https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_addendum_to_oakley_greenwood_cba_-_higher_meter_cost_sensitivity_-_august_2023.pdf.

This new regulatory mechanism will:

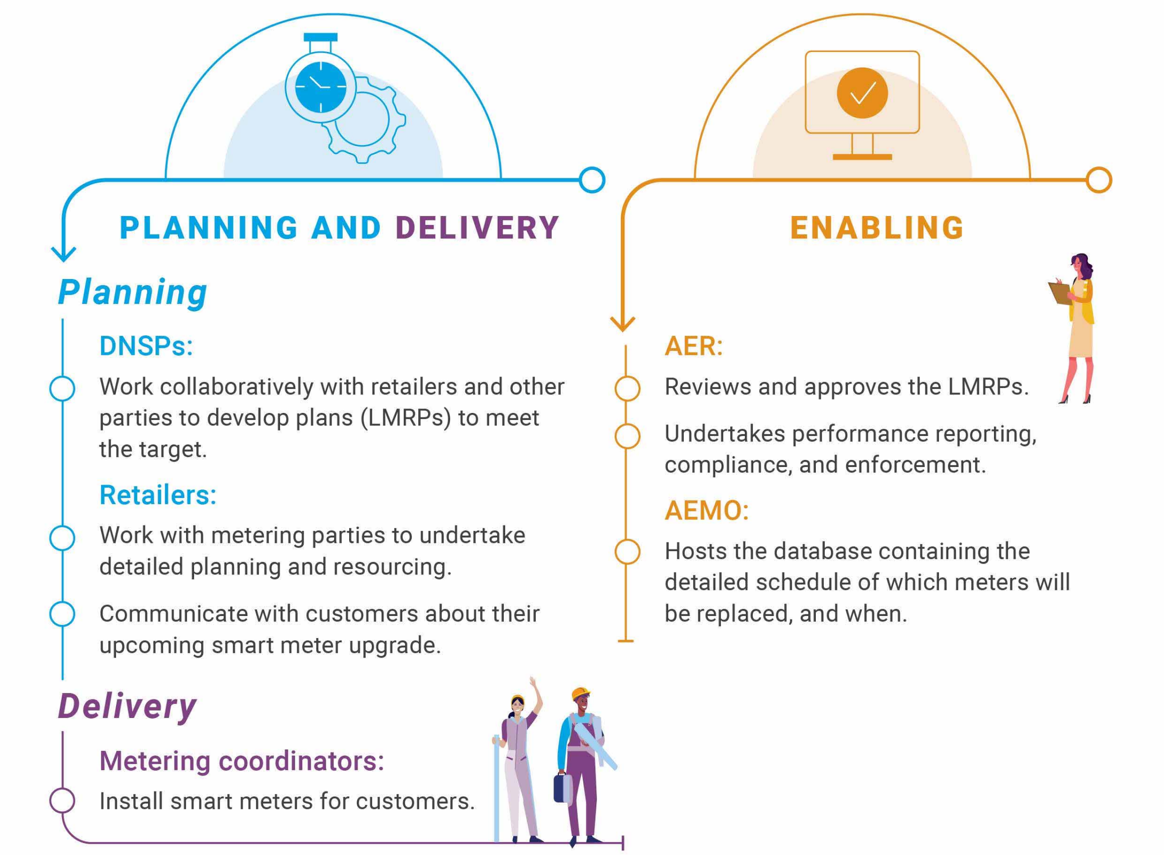
- deliver a faster, more efficient and less costly rollout of smart meters than is possible under the existing regulatory framework, whilst minimising regulatory burden on industry
- promote transparency, by requiring DNSPs to justify their LMRPs against a set of clearly defined principles and the LMRP objective
- promote cooperation and consultation across industry to deliver the deployment program in a way that best achieves the long-term interests of consumers
- provide sufficient flexibility to industry to work in ways that best suit their customer base and business needs
- give retailers and MCs certainty of where and when smart meters will need to be deployed over the acceleration period, allowing them to plan resource requirements.

Retailers and metering parties have the option to replace meters ahead of the LMRP meter replacement schedules if they choose to.

The final electricity rule establishes the new LMRP mechanism

The below figure outlines the roles of different stakeholders in planning, delivering, and enabling the LMRP process.

Figure 3.1: Stakeholder roles in the LMRP process



Source: AEMC

The final electricity rule requires DNSPs to develop LMRPs

DNSPs will be required to develop LMRPs in accordance with the 'LMRP objective'.[28]

Box 2: LMRP objective

To replace all existing legacy meters with a type 4 meter in a timely, cost-effective, fair, and safe way, during the LMRP period.

These LMRPs will be public facing documents that outline when legacy meters in different areas are due to be replaced with smart meters, from 2025–2030. They will be published on the AER's website, so that customers have visibility of the smart meter rollout — which enhances transparency and supports social licence.

These LMRPs must include:[29]

- An outline of the smart meter rollout profile. This will show the proposed groupings (for example, by postcodes or suburbs) that are scheduled for meter replacements in each 'interim period' from 2025 to 2030, and the total number of meters to be replaced in each year. [30]
- An explanation of how the LMRP objective and LRMP principles have been applied (outlined further below), which may include supporting information and strategies that underpin the LMRPs.
- A description of the DNSPs' consultation processes to develop the LMRPs, including who was consulted and how, what was learned through this consultation, and how the feedback shaped the plan.

The LMRP objective and LRMP principles promote transparency and flexibility

The LMRP objective and LRMP principles are designed to give DNSPs and affected parties the flexibility to develop LMRPs in a way that accommodates different jurisdictional circumstances, whilst still meeting the LMRP objective. The LRMP principles also give retailers certainty as to what factors DNSPs must consider when developing the LMRP.

There are four guiding principles:[31]

Box 3: LMRP principles

1. **Approximately 15–25 per cent of legacy meters should be planned for replacement in each interim period.** An interim period is each 12-month period commencing on 1 December within the LMRP period. This principle provides clear guidance for DNSPs and affected parties when developing LMRPs, and ensures the replacement program is not back-ended. This would mitigate the risk that retailers do not have enough time to address unforeseen issues by the 2030 target.
2. **DNSPs should have regard to the overall efficiency of the LMRP, including costs and potential cost savings for affected market participants.** DNSPs should consider grouping installations

28 Clauses 11.177.1 and 11.177.2(a) of Schedule 3 of the *National Electricity Amendment (Accelerating smart meter deployment) Rule 2024 No.20* (**Electricity Amending Rule**).

29 Clause 11.177.2(b) of the Electricity Amending Rule.

30 Per Clause 11.177.1 of the Electricity Amending Rule, 'interim period' means each 12-month period commencing on 1 December within the LMRP period, with the first period commencing on 1 December 2025.

31 Clause 11.177.2(c) of the Electricity Amending Rule.

by postcodes, zone substations, and/or meter reading routes to support coordination and delivery efficiencies.

3. **DNSPs should have regard to the impact of LMRPs on retailers and other affected stakeholders.** DNSPs are required to consult with key stakeholders, identify relevant concerns with the draft LMRP, and address those concerns in the LMRP proposal to the AER. Stakeholders are expected to help shape the replacement profile to ensure it is achievable.
4. **DNSPs should have regard to appropriate and efficient workforce planning, including in regional areas.** DNSPs are required to consider how the parties will utilise local work forces in a way that avoids moving installers every year or creating a local boom-bust cycle. Considering labour market conditions for electricians and the supply of metering components in the LMRPs will help retailers meet their obligations.

In response to the draft determination, stakeholder submissions were broadly supportive of the LMRP process and principles as an effective mechanism to deliver the accelerated rollout of smart meters.[32] We consider that our LMRP principles are fit for purpose; we have therefore not made any changes to the principles for the final rule.

Some stakeholders considered that the upper and lower bounds of the replacement targets should be adjusted to allow for a slower start, and to mitigate the risk of the bulk of replacements being left until the final period.[33] We consider that there is sufficient flexibility in the existing 15 – 25 per cent per year replacement band for the LMRPs to incorporate lower replacement targets in the first and final years of the acceleration period, if this is required. We also note that under the principles, DNSPs are expected to have regard to retailers and other impacted stakeholders when developing LMRPs to ensure that the plans are deliverable.

Other stakeholders considered that there should be specific requirements in the principles to ensure DNSPs and retailers coordinate efforts to efficiently manage shared-fuse sites, and meter replacements for life support customers.[34] We consider that the LMRP process, including the objective and principles, already provides a means for relevant parties to address these matters:

- in their explanations of how the LMRP objective and LRMP principles have been applied, DNSPs may outline industry strategies to manage shared-fuse sites and life support customers, among other issues
- as part of the LMRP approval process, DNSPs will be required to engage with stakeholders and demonstrate how they have addressed any concerns.

This will help support effective stakeholder coordination throughout the LMRP planning and delivery process.

The final electricity rule will require DNSPs to consult on the LMRPs

By no later than 28 February 2025, and before submitting their LMRP proposals to the AER, DNSPs are required to:[35]

- provide a draft of their LMRPs to affected retailers and MCs

32 Submissions to draft determination: AGL (p. 3); Alinta (p. 2); ENA (p. 2); Endeavour Energy (p. 2); Intellihub (p. 2).

33 Submissions to draft determination: Ausgrid (p. 4); Plus ES (p. 3).

34 Submissions to draft determination: AGL (p. 3); ENA (p. 2); Plus ES (p. 5).

35 Clause 11.177.3 of the Electricity Amending Rule.

- provide a schedule specifying the legacy meters and corresponding National Meter Identifiers (NMIs) to be replaced in each interim period under the LMRP (the LMRP meter replacement schedule) to affected retailers and MCs
- invite feedback on the draft LMRP from affected stakeholders.

The DNSPs' LMRP proposals are due to be submitted to the AER by 30 June 2025.

To strengthen the consultation requirements, DNSPs will be required to demonstrate to the AER that they have met these requirements by including in the LMRP proposal:

- an explanation of how the LMRP is consistent with the LMRP objective and principles[36]
- a description of how retailers, metering parties and other relevant and affected stakeholders were engaged in developing the proposal, relevant concerns raised through that engagement, and how those concerns have been addressed.[37]

This approach aims to support flexibility to encourage collaborative consultation in the development of the plan, whilst minimising regulatory burden on industry.

The AER will have a light-touch oversight role

Following DNSPs' submission of LMRP proposals to the AER by 30 June 2025 (as noted above), the AER will be required to approve the LMRPs no later than 29 August 2025.[38] This allows the acceleration program to commence 1 December 2025.

In assessing the LMRPs, the AER is required to consider whether DNSPs have met the LMRP requirements in developing the LMRPs. This includes whether the LMRPs meet the prescribed LMRP principles and LMRP objective, include the required information, and have met consultation requirements. The AER is not required to assess the merits of each DNSP's LMRP, as the AER notes in its submission.[39]

If the AER is satisfied that the LMRP complies with the LMRP requirements, it must approve the LRMP and then publish it on its website.[40] The final rule also outlines the process to occur if an LMRP does not comply with the relevant requirements.[41]

The Commission considers that this 'light-touch' regulatory approval process is appropriate and minimises regulatory costs. We do not see significant value in the AER undertaking a more detailed assessment — for example, by further scrutinising whether the LMRPs' proposed meter retirement scheduling is optimal. In its submission to the draft determination, the AER noted that enacting these roles, as well as the new compliance process discussed in section 3.1.3 of this chapter, will have a material impact on AER resourcing.[42]

Timely completion of the deployment is the most important objective. We expect industry participants to collaboratively design a process that can deliver against that objective.

The final electricity rule requires DNSPs to communicate the LMRP meter replacement schedules to retailers

Under the final electricity rule, DNSPs must communicate to retailers the schedule of meters that they are to replace under the LMRP.

36 Clause 11.177.2(b)(2) of the Electricity Amending Rule.
37 Clause 11.177.2(b)(3) of the Electricity Amending Rule.
38 Clause 11.177.4(b) of the Electricity Amending Rule.
39 AER submission to draft determination, pp. 6–7.
40 Clause 11.177.4(c) of the Electricity Amending Rule.
41 Clause 11.177.4(e) - (g) of the Electricity Amending Rule.
42 AER submission to draft determination, p. 2.

DNSPs must communicate this information in accordance with the below steps:[43]

Step 1: During consultation on the draft LMRP, DNSPs must provide the LMRP meter replacement schedules to affected retailers and MCs. We expect DNSPs to consult on how these meter replacement schedules will be provided. This information should be communicated in a consistent, standardised, and accessible format — preferably in the same format across all DNSPs.

Step 2: Following AER approval of the LMRPs, DNSPs must provide meter replacement schedules to affected retailers and MCs.

Step 3: By no later than 27 November 2025, DNSPs must record the LMRP meter replacement schedules in the Market Settlements and Transfer Solutions (MSATS) system (box 4), in accordance with relevant procedures.

Box 4: Market Settlements and Transfer Solutions (MSATS)

MSATS is an IT system that AEMO operates, and market participants use to record data that supports energy market settlement and retail competition. MSATS functions as the market's metering 'register' and database. AEMO and market participants use it to fulfil their obligations under the NER.

The MSATS information noted in step 3 above will be available throughout the duration of the acceleration program. To enable this, by 26 October 2025, AEMO must review and update MSATS and any associated procedures to specify the information that must be recorded by a DNSP in relation to an approved LMRP.

This solution was not contemplated in the Review. Following further consultation leading up to the draft determination, the Commission established that using MSATS to communicate LMRP meter replacement schedule information will minimise regulatory burden on industry. This approach leverages an existing system that can:

- be updated as frequently as needed
- provide real-time information to relevant market participants
- act as a 'single source of truth' regarding meter replacement schedules, housed in an environment that is already visible to all relevant parties whenever they need to see it.

Alternatives, such as DNSPs regularly issuing updates to relevant stakeholders via email or other means, would likely be more burdensome and costly, requiring regular manual handling.

A further benefit of using MSATS to communicate this information is that it helps to manage the impacts to the rollout of customer 'churn' between retailers. Without a seamless and low-cost way of updating LMRPs to reflect churn near to real-time, they would become progressively inaccurate over the duration of the five-year deployment period.[44]

Using MSATS, retailers and MCs would have on-demand access to any updates to their replacement requirements in near real-time. This requirement also supports the AER's annual

43 Clauses 11.177. 3 and 11.177.4 of the Electricity Amending Rule.

44 This captures customer churn for sites that are due to be replaced in a subsequent interim period, as distinct from meters due to be replaced within the current period. For the latter, the new retailer will be expected to replace the legacy meter by 2030, noting the challenges retailers may face to adjust their schedules within period. Retailers are expected to have incentives to replace customer sites 'won' within a period to the extent that they can still achieve geographical efficiencies, and have adequate time to properly notify the customers. Further, retailers must report their performance in managing within period customer churn to the AER. Nevertheless, we are concerned some retailers may seek to delay meter replacements if they have the opportunity (for example, for 'hard-to-do' sites or customers who may be perceived as 'lower value'). So, we have sought to minimise the impact of customer churn by creating a process for the interim targets to be updated at the start of each period.

performance reporting and compliance considerations — providing accurate interim target information that retailers must report against.[45]

This MSATS requirement was supported by several stakeholder submissions.[46]

Access to NMI Standing Data to support LMRP planning

Some stakeholders sought further clarification regarding what detailed NMI level information should be shared with retailers and MCs, and proposed a new provision to allow MCs increased access to NMI Standing Data to help plan meter replacements under the acceleration program.[47]

To clarify our position (which we maintain in this final rule), in providing the LMRP meter replacement schedules to affected retailers and MCs under steps 1 and 2 above, DNSPs must not provide information to market participants that are not otherwise able to access that information in accordance with NER clause 7.15.5 (which governs access to NMI Standing Data).

Similarly, under step 3, retailers and MCs will not be able to access a customer's NMI Standing Data unless they are the Financially Responsible Market Participant (FRMP) or until appointed as the MC for each connection point, respectively.

NMI Standing Data is confidential information under the NER.[48] Retailers and MCs may gain an unfair competitive advantage if they have access to NMI Standing Data for a connection point for which they are not the FRMP or appointed MC. This is commercially sensitive information, and there may be privacy concerns.

We consider the potential competition risks and complexity that would be created by introducing any proposed exception to NER clause 7.15.5, as part of the acceleration program, do not outweigh any potential planning benefits. As noted in section 3.1.2 above, we expect DNSPs to work collaboratively with industry to plan and deliver meter placements over the acceleration program.

The final electricity rule requires retailers to implement the LMRPs

Retailers are responsible for implementing the LMRPs, by arranging for meters to be upgraded in line with the schedules developed by the DNSPs.[49] Retailers will appoint MCs, who in turn visit customer sites to install smart meters.

Retailers will also be responsible for communicating with customers ahead of their meter upgrade, and providing them with important information regarding their smart meter. This is outlined in further detail later in this chapter in section 3.4.1.

The LMRPs include yearly interim targets that retailers must use its best endeavours to meet,[50] and a final target of universal penetration by 2030.[51] Retailers are required to report on their annual performance to the AER. This is also outlined in further detail in section 3.1.3 below.

The final electricity rule allows LMRPs to be revised under certain circumstances

Over the five-year accelerated deployment period, there may be unforeseen circumstances that impact a retailer's ability to deliver meter installations in accordance with the LMRP. This might

45 In the Review final report, the Commission recommended requiring the NMI schedule information to be provided once by the DNSPs before the start of the acceleration program, which would then (statically) set the future interim targets.

46 Submission to draft determination: Alinta (p. 2); Ausgrid (p. 4); Plus ES (pp. 3–5); Engie (p. 2).

47 Submission to draft determination: SA Power Networks (p. 6); Intellihub (pp. 4–6).

48 Clause 7.15.1(a) NER.

49 Clause 11.177.5(g) and 11.177.6 of the Electricity Amending Rule.

50 Clause 11.177.6(d) of the Electricity Amending Rule.

51 Clause 11.177.7 of the Electricity Amending Rule.

include circumstances such as unforeseeable field resource or meter equipment supply constraints, natural disasters, or other weather events.

The final rule includes a process that allows retailers to apply for amendments to the schedule of meters retired over the acceleration period, supporting the need to flexibly respond to unforeseen issues.[52]

To trigger this process, a retailer can put forward an amended version of the LMRP for the relevant DNSP's consideration. The DNSP may agree to amend an LMRP if it appears to the DNSP that the plan is affected by a material error, or a material change of circumstances or event.[53] The relevant DNSP and the AER must then re-apply the LMRP approval process (as outlined above).

3.1.3 The final electricity rule introduces performance reporting and compliance obligations

Reporting and compliance obligations will support the acceleration program

Performance reporting obligations promote transparency and accountability

The final electricity rule requires retailers and metering parties to report on their performance against meeting the interim targets and 2030 goal.[54] This will promote transparency and accountability, and support the timely deployment of smart meters. Performance reporting will also incentivise performance improvement, and support the AER in its compliance monitoring and enforcement activities.

The AER may seek further information from 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 will create stronger incentives for retailers to address any issues that may prevent successful replacements. Retailers can provide the AER with additional context if they are not meeting the interim targets, and assurances that they are on track to ultimately meet the 2030 target.

Under the final rule, the information provided to the AER is targeted, to minimise regulatory burden.

Civil penalties will help incentivise achievement of the 2030 target

We consider that financial incentives for retailers to meet the 2030 target are appropriate to support the timely deployment of smart meters. Any penalties should be proportionate to the negative impact on consumers, if retailers do not meet their obligations.

Some stakeholders submitted that civil penalties should apply to the interim and final targets, whilst others proposed more limited use of civil penalties.[55] Our position is that:

- financial incentives for retailers to meet the 2030 target are required and proportionate to support the timely deployment of smart meters
- penalties are not necessary for interim targets because reputational and other incentives created by performance reporting, as well as the final 2030 target, provide sufficient incentives for retailers to meet the interim targets.

This is consistent with our position in the Review and draft rule. Therefore, the Commission recommends that clause 11.177.7 should be a tier 1 civil penalty provision.[56]

52 Clause 11.177.5 of the Electricity Amending Rule.
53 Clause 11.177.5(a) of the Electricity Amending Rule.
54 Clause 11.177.8 of the Electricity Amending Rule.
55 Submissions to draft determination: Ausgrid (p. 5); Energy Queensland (p. 14); EnergyAustralia (p. 6).
56 See section C.5 of this final determination for more information on civil penalty recommendations.

The final electricity rule introduces new performance reporting and compliance obligations for retailers, and a monitoring and enforcement role for the AER

The final electricity rule requires retailers to report against their performance to the AER, which will oversee implementation of the acceleration program

Under the final electricity rule, retailers are required to report on their performance to the AER.[57]

Specifically, retailers will be required to report on their high-level performance against their LMRP meter replacement schedules.[58] The relevant indicators against which retailers' performance will be measured are outlined in the final rule.[59] As discussed above, retailers will be required to explain their performance against the interim and final targets, and outline their plan to get back into compliance (if necessary).[60]

The AER must report on the retailers' performance annually, following each interim period, and at the conclusion of the LRMP period. Within five months of the end of each interim period, the AER must report on retailers' compliance with the interim targets and progress against the LRMP objective.[61] Then, no later than 31 December 2031, the AER must also report on retailers' compliance with the final targets and whether the LMRP objective has been met.[62] The AER may provide commentary on the reasons for any material differences between retailer results. We consider that the AER may seek further information from the retailers if, for example, a retailer's performance is an outlier, and it appears to be non-compliant.

Several stakeholder submissions proposed options to reduce the burden of the performance reporting requirements, such as relying on AEMO to provide the information to the AER. Some stakeholders considered that the AER should be required to consult on these reporting requirements.[63]

We consider that the reporting and compliance process is appropriate, and have not made any changes for the final rule.[64] We note that the accelerated smart meter deployment is a significant reform, and that a robust reporting and compliance framework will be important in ensuring that the reform is delivered and benefits are realised. We consider it is necessary to prescribe the performance reporting requirements, rather than rely on the AER to develop guidelines, due to timing constraints and level of consultation already undertaken throughout the Review process. We also note that under the reporting and compliance framework, the AER has flexibility to engage directly with retailers on how they should provide the required qualitative and quantitative information.

The final electricity rule recommends the introduction of new civil penalties for non-compliance with the 2030 target

57 Clause 11.177.8 of the Electricity Amending Rule.

58 Consistent with existing retailer reporting requirements, compliance with this new reporting requirement would be subject to civil penalties, to ensure retailers provide the data and information to the AER as is prescribed in the final rule.

59 Clause 11.177.8(a) of the Electricity Amending Rule. The Commission has refined some of the performance indicators and reporting requirements compared to the Review recommendations and rule change request. We added indicators to create additional transparency around the impact of customer churn to clearly include a measure of: (a) within period churn to recognise retailer efforts to quickly turn those replacements around, and (b) the backlog of meters that will need to be replaced by 2030. We also removed performance indicators that may be seen as a pre-defined exception for retailers to not meet the interim and final targets.

60 The Commission considered whether to include indicators that pre-define exceptions to meeting the interim targets, such as customer refusal or site access issues. We found upfront exceptions could create negative incentives for retailers to meet their targets. Minor divergences from the LMRP meter replacement schedules 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. Further, introducing processes to record and track exceptions would create administrative burdens and complexity that are not proportionate to the benefits.

61 Clause 11.177.8(d) of the Electricity Amending Rule.

62 Clause 11.177.8(e) of the Electricity Amending Rule.

63 Submissions to draft determination: Alinta (p. 2); AEC (p. 2); AER (p. 6); EnergyAustralia (p. 6); Momentum Energy (p. 2).

64 Other than the relevant dates, which have been extended to reflect the extension to the publication of this rule change and timings under the final rule.

The Commission recommends that civil penalties apply to retailers for non-compliance with the final 2030 target, but not the interim targets.

Where a legacy meter has been scheduled for replacement in an LMRP, the retailer must:

- use best endeavours to ensure it is replaced in accordance with the LMRP meter replacement schedule to meet the interim targets for each interim period.[65]
- meet the final target of universal penetration of smart meters by 2030 (the replacement deadline) — subject to the retailer being able to justify any failure to meet the target, based on a reasonable assessment of the circumstances.[66]

Therefore, the Commission recommends that clause 11.177.7 should be a tier 1 civil penalty provision, but does not recommend any civil penalties apply to clause 11.177.6.

If a retailer is unable to replace a meter in accordance with the LMRP, or the meter is not functioning as required, it will be open to the retailer to report the reasons to the AER.[67]

Where a small customer switches retailers during the final interim period (1 December 2029 – 30 November 2030), but before they receive a smart meter upgrade, the incoming retailer must ensure the legacy meter is replaced by the later of 30 November 2030, or six months after the small customer switches retailers.[68]

3.2 Enabling better access to power quality data

Box 5: Final determination

2 Access to power quality data	• DNSPs can better manage their networks to reduce network costs for customers • saves energy, minimises network safety risks, and lifts hosting capacity.

Giving DNSPs better access to basic PQD, free of cost, allows DNSPs to better understand the network and unlocks a range of benefits for networks, consumers, and the broader energy system.

The final rule:

- defines basic PQD
- allows local DNSPs, the AER and AEMO to access or receive basic PQD free of charge
- allows MC, MPs, MDPs to access or receive basic PQD on commercial terms
- imposes responsibilities and requirements on MCs to enable better access for DNSPs
- makes consequential amendments to facilitate the basic PQD arrangements.

3.2.1 The final electricity rule gives DNSPs better access to basic PQD to unlock a range of benefits for stakeholders

PQD refers to the characteristics of the power supply as measured by the meter. The final rule introduces a new defined term for basic PQD which comprises measurements of voltage, current,

65 Clause 11.177.6(d) of the Electricity Amending Rule.

66 Clause 11.177.7 of the Electricity Amending Rule.

67 Clause 11.177.8(a)(5) of the Electricity Amending Rule.

68 Clause 11.177.7(b) of the Electricity Amending Rule.

and phase angle (basic PQD). The final rule does not define advanced PQD, but advanced PQD would include measurements in addition to those identified for basic PQD (advanced PQD).

For DNSPs, access to information about a small customer's electrical power supply will be increasingly important for the safe and efficient operation of the distribution system. Giving DNSPs better access to basic PQD supports their understanding of the network, and allows DNSPs to:

- save energy by maximising CER hosting capacity
- reduce line losses
- minimise safety risks, such as through earlier detection of neutral integrity faults and voltage excursions at customer premises
- drive down costs within the distribution network by extracting the most value from the existing distribution network assets and optimising future investment decisions.

The proposed changes to basic PQD access and exchange arrangements will also promote better outcomes for consumers and the broader energy system by:

- improving standardisation in the structure, types, sequencing, and frequency of basic PQD provided across market participants
- reducing differences in exchange architectures or methods for basic PQD access
- addressing a potential lack of competitive pricing where basic PQD is required from a high percentage of sites.

3.2.2 The final electricity rule gives DNSPs access to basic PQD free of charge

DNSPs require access to basic PQD to efficiently operate and improve the safety of the distribution system. The Review identified several DNSP use cases that basic PQD enables from small customer meters, such as detecting neutral integrity issues and energy and meter theft. Most of the use cases identified also need basic PQD from a large portion of meters.[69]

Under current arrangements, metering parties hold and control access to PQD generally, and DNSPs can only receive PQD through commercial negotiation with metering parties. This means that metering parties can charge DNSPs prices well above the marginal cost to receive PQD. In these circumstances, DNSPs can have limited bargaining power to negotiate efficient prices for access to basic PQD, leaving them as price-takers. This outcome can lead to higher than necessary costs for DNSPs for access to the data, which are ultimately passed onto customers.

The final rule introduces new arrangements to the metering framework to give DNSPs access to basic PQD from small customer meters on an ongoing basis without charge.[70] This framework is consistent with the approach outlined in the Review, which was supported by stakeholders. Under the final rule, basic PQD is to be provided free of cost, compared to advanced PQD, which is negotiated on a commercial basis.[71]

69 AEMC, Review final report, pp. 117-118 (Table E.1 in Appendix E.3.2).

70 Clauses 7.3.2(j)-(k) and 7.15.5(c2) of the Electricity Amending Rule.

71 The basic PQD service is the basic PQD collected, processed and delivered in line with the basic PQD arrangements in the final rule and associated procedures free of charge and on an ongoing basis. The advanced PQD service is any service that materially differs from the basic PQD arrangements. An advanced PQD service can include basic PQD collected, processed and delivered differently than under the basic PQD arrangements and/or the collection, process and delivery of other electrical parameters. See further information about the advanced PQD service in the AEMC, Review final report, pp. 122-126.

We understand that MCs and DNSPs may have existing agreements to provide basic PQD and/or advanced PQD. Despite these agreements, MCs must give DNSPs the basic PQD in line with the basic PQD arrangements in the final rule and associated procedures unless exempted.[72]

The final rule adopts a flexible design of the arrangements. It will allow AEMO to enable a basic PQD service with a standardised exchange architecture and appropriate service levels through its processes and procedures (see section 3.2.4). This approach is consistent with the design of the metering framework.

3.2.3 Several components will establish the new arrangements in the NER

There will be a basic PQD definition

The final electricity rule establishes a basic PQD definition, which will be captured by the expression 'basic power quality data'.[73] The purpose of the definition is to:

- clarify the electrical parameters that comprise basic PQD under the new PQD arrangements. These parameters are voltage, current, and phase angle, to be delivered in accordance with AEMO procedures.
- ensure that DNSPs receive uniform basic PQD from all small customer meters necessary for the basic PQD use cases identified from the Review.

The definition does not provide the option for power factor to be represented as a ratio of active power to the apparent power in a power supply. We agree with stakeholder feedback to the draft determination that power factor should only be represented as a phase angle.[74] Unlike power factor as a ratio, phase angle provides the direction of active and reactive power flow important to enable the basic PQD use cases.[75] This will also allow both industry and AEMO to avoid additional costs in designing and building systems, processes and procedures for optional parameters.

Several stakeholders proposed other refinements to the basic PQD definition, such as including additional details regarding basic PQD.[76] Some also proposed to define or to reference advanced PQD in the rules,[77] to broaden the basic PQD definition to include advanced PQD,[78] or for a definition of freely available data instead of differentiating between basic PQD, advanced PQD, and meter data generally.[79]

We have not included these proposed changes in the final rule. We support the metering framework's differentiation of types of meter data, each of which is important for a different purpose. For this final rule, this means the recognition of basic PQD in the NER, which we consider essential in resolving DNSP access issues to basic PQD.

The new arrangements in the NER apply to basic PQD and, as further explained in section 3.2.4, the Commission considers that AEMO procedures are the appropriate instrument to contain additional details for basic PQD and the basic PQD service.

These new basic PQD arrangements do not impact MCs' and other requesting parties' existing ability to commercially negotiate PQD services, including advanced PQD services. As MCs and DNSPs should already be able to negotiate the terms, conditions, and prices of advanced PQD on

72 See the categories of exemptions in section 3.2.3.

73 A new definition in Chapter 10 NER introduced by Schedule 2 of the Electricity Amending Rule

74 Submissions to draft determination: AGL, p. 8; Bluecurrent, p. 4; ENA, p. 3; Endeavour Energy, p. 9; PLUS ES, p. 8; SA Power Networks, pp. 3-4.

75 Submissions to draft determination: ENA, p. 3; Endeavour Energy, p. 9; SA Power Networks, pp. 3-4.

76 Submissions to draft determination: Bluecurrent, pp. 4-5; ENA, p. 3; Intellihub, p. 7; PLUS ES, p. 8.

77 Submissions to draft determination: Energy Queensland, pp. 2-3; Intellihub, pp. 7-8; PLUS, ES, p. 8.

78 Essential Energy, submission to draft determination, p. 1.

79 PIAC, submission to draft determination, pp. 6-7.

a commercial basis, we do not consider that the NER needs to define advanced PQD. We consider existing provisions of the NER enable advanced PQD to be commercially negotiated.[80]

MCs will be responsible for giving basic PQD to local DNSPs

The final electricity rule makes MCs responsible for providing basic PQD to local DNSPs.[81] This differs from the draft rule, which proposed requirements on both the MC and MDP to give basic PQD. Under the final rule, there is no requirement for MPs or MDPs to give basic PQD or be accredited to conduct basic PQD obligations on behalf of MCs.

We agree with stakeholders that because basic PQD is not involved in financial settlements and billing like metering data, MDPs do not have to be accredited to give basic PQD, and that basic PQD does not need to be treated in the same manner as metering data.[82] We expect the revised approach under the final rule will enable a faster and more streamlined implementation of the basic PQD arrangements.

However, the final rule does require MCs to process basic PQD.[83] For example, the MC must confirm the basic PQD came from the associated small customer meter at a NMI. Clarifying MC responsibilities in processing basic PQD will enable AEMO to develop procedures to ensure that this necessary processing occurs.

MCs will be exempt from giving basic PQD in certain circumstances

In line with the Review final report and stakeholder feedback,[84] MCs will not be required to give basic PQD where the small customer meter:[85]

- is not capable of supporting remote collection and communication of basic PQD[86]
- is temporarily unable to collect and/or communicate basic PQD[87]
- is installed before 1 December 2018
- is a type 4A[88] or type 8B meter.[89]

Local DNSPs, MCs, MPs, MDPs, AEMO and the AER will have access to basic PQD

The new basic PQD arrangements in our final electricity rule give basic PQD access to:

- local DNSPs free of charge, which enables them to receive the basic PQD service from small customer meters within their network regions.[90]
- MCs, MPs, and MDPs so that they can conduct the basic PQD obligations placed on them by the arrangements or delegated to them by MCs. However, unlike DNSPs, this access is provided on commercial terms.[91]

80 Clause 7.6.1(b) of the NER provides for the commercial negotiation on terms and conditions, including price, services performed by Metering Coordinators, which could include a service for the provision of advanced PQD. See also AEMC, Review final report, p. 122.

81 Clauses 7.3.2(j)-(k) of the Electricity Amending Rule.

82 Submissions to draft determination: Bluecurrent, pp. 1, 6-8; Energy Queensland, p. 2; Intellihub, pp. 6, 9-10; PLUS ES, pp. 9-10.

83 Clause 7.3.2(j) of the Electricity Amending Rule.

84 AEMC, Review final report, p. 111 (Box 2); Submissions to draft determination: Bluecurrent, p. 8; Intellihub, pp. 10-11; PLUS ES, p. 24; Intellihub, submission to the *Unlocking CER benefits through flexible trading* draft rule, p. 7.

85 Clauses 7.3.2(l)(1)-(4) of the Electricity Amending Rule.

86 This exemption does not apply to small customer meters that are capable of supporting the remote collection and communication of basic PQD, but have not been configured to provide basic PQD. We expect MCs to configure small customer meters to provide basic PQD as part of implementation of the basic PQD arrangements.

87 For example, this could apply where the meter malfunctions or experiences a telecommunications outage.

88 This includes type 4 meters that have had their remote communications deactivated.

89 The *Unlocking CER benefits through flexible trading rule* introduced small customer type 8B meters at secondary settlement points. We consider that there is no clear necessity for basic PQD from small customer meters at secondary settlement points to better enable the basic PQD use cases.

90 Clause 7.15.5(c2)(1) of the Electricity Amending Rule.

91 Clause 7.15.5(c3)(1)-(3) of the Electricity Amending Rule.

- the AER and AEMO to monitor and enforce the basic PQD arrangements. MCs are to provide this access free of charge.[92]

Stakeholders proposed for other persons to have basic PQD access on the same terms as DNSPs,[93] or for obligations on MCs to make basic PQD available to other persons.[94] They considered that this would allow fair and equitable access to basic PQD for different parties,[95] and deliver network and customer benefits, such as more flexible network management mechanisms[96] and better CER coordination, monitoring and support.[97]

We do not support this approach. The basic PQD arrangements in the final rule have been designed to specifically enable better access for DNSPs to basic PQD. We are currently considering a separate rule change to give customers and their agents access to real-time smart meter data.[98] That rule change proposes reforms to real-time data access in line with recommendations from our Review.[99]

The final electricity rule makes consequential amendments to support the new PQD arrangements

These consequential amendments include:

- classifying basic PQD as confidential information[100]
- refining the responsibilities of MCs and AEMO to implement the basic PQD arrangements.[101] This includes placing an obligation on MCs to provide relevant NMI Standing Data with basic PQD.[102] This obligation is needed to support the basic PQD service, and is consistent with the findings from the Review.[103]

3.2.4 AEMO is required to update its processes and procedures to implement the basic PQD arrangements

In consultation with stakeholders, AEMO will lead work to update its processes and procedures to further develop the basic PQD framework by:[104]

- further defining basic PQD details and the basic PQD service, including the relevant NMI Standing Data[105]
- designing the exchange architecture and service levels to enable the basic PQD service[106]

92 Clause 7.15.5(c2)(2)-(3) of the Electricity Amending Rule.
93 Submissions to draft determination: AGL, p.6; Clean Energy Council, p. 2; EnergyAustralia, p. 6; Origin Energy, p. 5; PIAC, p. 7; sonnen Australia, pp. 1-2.
94 PIAC, submission to draft determination, p. 8.
95 Submissions to draft determination: AGL, p. 6; sonnen p. 2.
96 PIAC, submission to draft determination, p. 7.
97 Submissions to draft determination: AGL, p. 6; EnergyAustralia, p. 6.
98 See AEMC, *Real-time data for consumers*, https://www.aemc.gov.au/rule-changes/real-time-data-consumers.
99 AEMC, Review final report, Appendix F.
100 Clause 7.15.1(a)-(b) of the Electricity Amending Rule.
101 Clauses 7.1.1(g), 7.3.1(a)(3), 7.3.2(m)-(n), 7.10.3(b), 7.15.4(b1), 7.15.5(b), 7.16.6C(a)-(d) of the Electricity Amending Rule.
102 Clauses 7.3.2(j)-(k) of the Electricity Amending Rule.
103 AEMC, Review final report, p. 111 (Box 2).
104 AEMC, Review final report, pp. 112-113.
105 Aspects of the basic PQD service not included in the final rule are defined in the AEMC Review final report. See AEMC, Review final report, p. 111 (Box 2).
106 AEMC, Review final report, pp. 114-115.

- specifying any other matters to be included in procedures to ensure the successful implementation and enforcement of the basic PQD service.[107]

Therefore, the final electricity rule requires AEMO to publish procedures relevant to basic PQD.[108]

Some stakeholders raised concerns about this approach in submissions to the draft determination. For example, they considered there was a risk that AEMO may deviate from implementing the basic PQD service as intended by the Review and this final rule determination.[109] Some stakeholders suggested that the final rule should include additional detail to reflect the basic PQD service agreed to by stakeholders,[110] and proposed an objective and/or principles to be included in the NER to ensure AEMO implements a basic PQD service envisaged by the Review.[111]

We consider that these matters are best described in AEMO procedures because, in contrast with the NER, the procedures give flexibility to implement the new arrangements and related technical matters. This includes circumstances where the arrangements must be adjusted to align more closely with the intent of the basic PQD service without the need for a rule change process. This approach is also consistent with the design of the metering framework in the NER and matters contained in AEMO procedures.

Therefore, we have not included these proposed changes in the final rule because:

1. We do not expect there to be any material change in circumstances that would require changes to the intended basic PQD service during implementation.
2. We are confident that AEMO will consider the work and findings of the Review, this final rule determination and stakeholder views during its consultation processes to implement the envisaged basic PQD service in line with the NEO. Our view is supported by the previous collaborative work of an AEMO-led industry technical working group, which considered the Review recommendations and the draft rule determination.

3.2.5 The basic PQD arrangements will commence on 1 July 2026

The basic PQD arrangements in our final electricity rule will apply to all small customer meters from 1 July 2026.[112] We consider the commencement date:

- reflects stakeholders concerns that a 1 July 2025 commencement date may not be achievable due to a range of implementation challenges[113]
- allows stakeholders to balance resources across competing implementation priorities, such as the developing LMRPs for the accelerated smart meter deployment
- gives time to AEMO to:
    - undertake a stakeholder consultation process for the PQD procedures
    - implement its Industry Data Exchange platform, which could be an option for industry to leverage for PQD delivery

107 This approach is in line with the existing framework and for metering data in AEMO's MDP service level procedures for MDP services. Other matters could include whether to allow DNSPs and MCs to agree to give DNSPs basic PQD in a different way from the standardised basic PQD service or not to provide it at all (see section 8 of the MDP service level procedures for MDP services). These bilateral agreements could accommodate circumstances where MCs give some or all of the basic PQD with higher resolutions, sampling volumes and/or faster delivery frequencies under an advanced PQD service. As a result, DNSPs may not require the delivery of some or all of the basic PQD under the basic PQD service.

108 Clause 7.16.6C(a)-(d) of the Electricity Amending Rule.

109 Submissions to draft determination: Bluecurrent, p. 5; ENA, p. 3; Intellihub, pp. 8-9; PLUS ES, p. 8.

110 Submissions to draft determination: Bluecurrent, pp. 4-8; Intellihub, pp. 6-7; PLUS ES, p. 6.

111 Submissions to draft determination: Intellihub, p. 9; PLUS ES, p. 8.

112 The commencement date of Schedule 2 of the Final Electricity Rule is 1 July 2026.

113 AEMO, Metering Services Review Draft High Level Implementation Assessment (August 2024); Submissions to draft determination: AEMO, p. 1; AGL, p. 6; Intellihub, p. 18; Momentum Energy, p. 3; Red and Lumo Energy, p. 5; PLUS ES, pp. 20-22; TasNetworks, p. 5.

- aligns with AEMO and industry's systems update cycles.

Our final rule also does not include other changes suggested by some stakeholders relevant to the commencement date, including:

- a mechanism for DNSPs to opt-in to the basic PQD arrangements based on network region readiness[114]
- reasonable endeavours obligations or a moratorium on MCs to meet their basic PQD obligations for a period of time after the commencement of the basic PQD arrangements[115]
- a transition period or arrangement to assist MCs to comply with their basic PQD obligations from the commencement date[116]
- a grace period where MCs are not subject to civil penalties for non-compliance.[117]

We consider that the 1 July 2026 commencement date provides stakeholders adequate time to implement the new arrangements and enable MCs to comply with their obligations under the final rule.

3.2.6 We recommend a new civil penalty to support basic PQD compliance

We recommend a new civil penalty for instances where MCs fail to provide basic PQD to DNSPs or where they share basic PQD with unauthorised third parties.[118] The proposed penalty will:

1. Protect consumer data. Basic PQD is data provided by consumers and becomes identifiable consumer data when provided with the customer's NMI. The penalty will deter disclosure of basic PQD to unauthorised third parties.
2. Encourage MCs to comply with their obligation to provide basic PQD to DNSPs. Under the proposed basic PQD arrangements, MCs will be responsible for giving basic PQD to DNSPs free of charge. The penalty will incentivise MCs to comply with their obligation, noting that there may not otherwise be sufficient financial incentive to ensure compliance.
3. Align with the civil penalty requiring MDPs to provide metering data and relevant NMI Standing Data to certain persons only.[119] As MCs will be responsible for giving basic PQD instead of MDPs under the final rule, it is appropriate for the proposed civil penalty to apply to MCs instead of MDPs.

We consider that this penalty is necessary to successfully implement the new basic PQD arrangements.

3.3 Providing customer safeguards

Box 6: Final determination

3 New customer safeguards	• protect customers from potential upfront charges and exit fees for new meters, and bill shock from unwanted retail tariff structure changes • builds social licence for the smart meter acceleration program.

114 AEMO, Metering Services Review – Draft High Level Implementation Assessment (August 2024), p. 7.

115 Submissions to draft determination: Bluecurrent, p. 8.

116 Submissions to draft determination: Bluecurrent, p. 9; SA Power Networks, p. 4.

117 Submissions to draft determination: TasNetworks, p. 5.

118 This would apply to clause 7.3.2(k) of the Electricity Amending Rule. See section C.5 of this final determination for more information on civil penalty recommendations.

119 Clause 7.10.3(a) of the NER.

Customer safeguards are critical in protecting customers from potential cost risks and in building and maintaining social licence for the smart meter acceleration program. Without social licence, consumers may resist changes which could risk the program's benefits.

The final rules:

- prohibit retailers from charging small customers any upfront costs or exit fees that relate to replacing a type 5 or 6 metering installation identified in an LMRP (this prohibition does not apply to new connections, or meter replacements initiated at the customer's request)
- introduce a two-year explicit informed consent period for any retail tariff structure variations following a smart meter upgrade
- require retailers to provide their customers at least 30 business days' notice when transitioning them to a different pricing structure during the LMRP period as a result of a change in meter type, as well as information on how to understand and manage the change
- introduce a new requirement for designated retailers to offer flat tariff structures to customers with smart meters, noting that this measure must be implemented by jurisdictions to come into effect.

3.3.1 The final electricity rule prohibits retailers from imposing any upfront charges for new smart meters

Prohibiting upfront charges will mitigate social licence risks

The smart meter acceleration program is expected to lead to significant net benefits for consumers. However, the timing of the benefits of smart meters will not necessarily match when the investment costs are incurred. This is because the program brings forward future investments, resulting in short-term cost impacts, while the benefits accrue over the longer term.

Upfront customer charges for smart meter deployments could create social licence risks and impact the overall success of the acceleration program.[120] Customers could refuse site access or be less willing to remediate any defects if they incur upfront smart meter costs. Any upfront charges applied inconsistently to individual customers may also be perceived as unfair, noting that all customers share the benefits of a smart energy system.

Explicitly prohibiting upfront costs (including exit fees) for smart meter deployments under an LMRP will help mitigate these risks and support the accelerated deployment program.

The final electricity rule prohibits any upfront charges or exit fees for the replacement of a legacy meter during the LMRP period

Currently, customers do not typically incur up-front costs associated with meter upgrades. Retailers generally pay annualised charges to MCs, which includes the capital and installation costs of meters. This industry practice covers most, if not all, of the total meter costs — smoothing retailer payments to MCs over time.

Although retailers do not typically pass on upfront costs to customers, they may change their pricing policies in the future, noting retailers are not prevented from doing so under the current regulatory framework. This could even occur when a customer has not requested a new meter.

120 Social licence in the context of the Review refers to the informal permissions granted by consumers for institutions to make investment decisions on their behalf.

Under the final electricity rule, retailers are prohibited from imposing any upfront charges or exit fees on small customers, when the meter upgrade relates to the replacement of a legacy meter identified in an LMRP during the LMRP period.[121] This excludes new connections and meter replacements that were initiated at the customer's request.

This protection applies to small customers whose meters are replaced under an LMRP, or meters that retailers choose to replace ahead of their scheduled replacement date in an LMRP, but during the LMRP period.

This protection does not apply under other types of smart meter deployments such as new connections, customer-initiated deployments, or deployments resulting from the small customer installing new equipment at the site (such as solar PV or a battery).

This protection will cease to apply from 31 May 2031. The regulatory burden of this rule change is low- or no-cost, noting that this approach is consistent with current practice.

3.3.2 The final retail rule establishes a new two-year explicit informed consent period prior to retail tariff variations

A new explicit informed consent period will help minimise negative customer impacts and support increased customer choice

Our final retail rule requires retailers to obtain a customer's explicit informed consent prior to changing the customers' retail tariff structure, following a smart meter upgrade.[122]

Requiring retailers to obtain a customer's explicit informed consent ahead of any retail tariff variations will help minimise the risk of negative customer experiences following a smart meter installation. This includes risks such as bill shock resulting from unexpected retail tariff changes, or changes that customers are not equipped to understand or respond to.

An explicit informed consent period will help restore customer choice regarding how they are charged for their energy usage. We consider that meaningful customer choice is important in building trust and support for the smart meter rollout and broader energy transition.

Under the new explicit informed consent period there will be strong incentives for retailers to provide customers with detailed and useful information explaining how they may be able to benefit under a proposed new retail tariff structure. This is important noting stakeholder feedback of anecdotal evidence that customers have not received sufficient information from their retailer about the impact of their new tariff, or how they can change their energy usage to benefit from it.

We also note that a key consumer benefit of smart meters is increased access to meaningful energy consumption information. A two-year new informed consent period before changes to retail tariffs will allow consumers to accumulate energy usage data and better understand their consumption patterns. This in turn will allow consumers to make more informed decisions about what retail tariffs best suit them. It will also give customers more time and opportunity to consider behaviour changes or invest in products that may allow them to take advantage of a cost-reflective tariff.

The final retail rule establishes a new two-year explicit informed consent period for retail tariff variations

121 Clause 11.177.9(a) in Schedule 4 of the Electricity Amending Rule.

122 Rules 2(2)(a) and (2)(3) in Schedule 3 of *National Energy Retail Amendment (Accelerating smart meter deployment) Rule 2024 No.6* (**Retail Amending Rule**).

The final retail rule introduces a new customer consent requirement relating to retail tariff changes following a smart meter deployment. Under this rule, there are no changes to existing network tariff arrangements. When a customer receives a new smart meter, a DNSP may apply a new cost-reflective network tariff to that customer's connection point, in line with the DNSP's TSS, which has been approved by the AER.

When a customer receives their new smart meter, the retailer may then offer the customer a new (for example, cost-reflective) retail tariff. As part of this offer, the retailer is required to give:[123]

- An estimate of what the customer's historical bill would have been for the preceding 12 months under the new varied retail tariff, compared to the bill they received under their existing tariff (to the extent that this information is available).[124] If there is only 3 – 12 months of data available, the retailer must provide an estimate of the historical bill based on the period of data that it does have available, and specify the timeframe that the estimate relates to.[125]
- supporting information for customers detailing how to understand, monitor, and manage their electricity usage (for example, through available apps or in-home displays).[126]

While retailers may offer customers new retail tariffs in these circumstances, the retailer must obtain the customer's explicit informed consent to proceed with a change to the customer's retail tariff.[127]

The nature of explicit informed consent is defined in section 39 of the National Energy Retail Law (NERL). We consider that the definition of explicit informed consent is robust, and therefore have not prescribed further detail in the final rule regarding how retailers must meet their explicit informed consent obligations with respect to retail tariff variations.

We note that the nature of explicit informed consent means the retailer (or person acting on behalf of the retailer), must clearly, fully, and adequately disclose all matters relevant to the customer. On this basis, when a retailer seeks a customer's explicit informed consent for a retail tariff variation, we expect retailers to make clear to the customer that the customer may remain on their existing (likely flat) tariff throughout the two-year explicit informed consent period, should the customer wish to.

If the customer gives their explicit informed consent, the retailer may change the customer's retail tariff type. The customer is not obliged to remain on their existing (likely flat) tariff. They may ask the retailer what alternate tariffs are available to them, or seek other offers with other retailers.

This new explicit informed consent period lasts for two years following the customer's smart meter deployment.[128] After two years, the retailer may move the customer to a new retail tariff without the customer's explicit informed consent. Under these circumstances, the retailer is required to give:[129]

- 30 business days' notice
- an estimate of what the customer's historical bill would have been for the preceding 12 months under the new varied retail tariff, compared to the bill they received under their existing tariff

123 Rule 2(2) in Schedule 3 of the Retail Amending Rule.
124 Rule 2(2)(f) in Schedule 3 of the Retail Amending Rule.
125 Rule 2(2)(g) in Schedule 3 of the Retail Amending Rule.
126 Rule 2(2)(h) in Schedule 3 of the Retail Amending Rule.
127 Rule 2(3) in Schedule 3 of the Retail Amending Rule.
128 See the definition of 'Explicit Informed Consent Period' in rule 1 in Schedule 3 of the Retail Amending Rule.
129 Rule 3 in Schedule 3 of the Retail Amending Rule.

- supporting information for customers detailing how to understand, monitor, and manage their electricity usage (for example, through available apps or in-home displays).

We expect that retailers that are focused on delivering good consumer outcomes will also advise customers if they have a flat tariff offer available.

Scope of application

This new explicit informed consent safeguard applies to customers who receive a tariff change as a result of a smart meter upgrade for any reason. This covers all smart meter deployment types, including deployments under the acceleration program, customer-initiated deployments, new connections, and where a malfunctioning legacy meter is replaced with a smart meter.

This safeguard does not apply:[130]

- if a customer moves into a premises that already has a smart meter
- if a customer changes retailer after they receive a smart meter
- where the variation to the tariff is a direct result of a benefit change and the retailer has provided the customer with a notice under rule 48A
- where the variation to the tariff is a direct result of a change to, or withdrawal or expiry of, a government funded energy charge rebate, concession or relief scheme
- in relation to premises of a business customer, where the retailer and the business customer have agreed that the relevant premises are to be treated as aggregated under rule 5
- where the variation to the tariff is a direct result of a change to any bank charges or fees, credit card charges or fees, or payment processing charges or fees applicable to the customer.

In response to the directions paper, we received stakeholder feedback that the proposed explicit informed consent requirement should not apply to business customers who have agreed to aggregate consumption under rule 5 of the NERR. [131] Under rule 5 of the NERR, small business customers may agree with their retailer to aggregate multiple premises and waive certain protections afforded to small customers under the NER and NERR. Such customers may have a significant number of locations and individual meters, and therefore choose to engage with their retailer on an aggregated basis. Customers must give their explicit informed consent to aggregate consumption under rule 5.[132]

We agree that the explicit informed consent requirement should not apply to small businesses that aggregate under rule 5. Therefore, the final rule includes this exception.[133] We consider that this is consistent with existing arrangements, whereby these customers choose to be effectively treated as large customers, and give their explicit informed consent to waive their right to certain small customer protections under the NER and NERR.

Duration of new explicit informed consent period

The new explicit informed consent period will commence for each customer when they receive a smart meter and will endure for two years from that point.

This is shorter than the three-year duration proposed in the directions paper, reflecting varied stakeholder feedback we received to the paper regarding the appropriate duration of an explicit informed consent period:

130 Rule 5(1) in Schedule 3 of the Retail Amending Rule.

131 Submission to directions paper, p. 2.

132 Rule 5(3) of the NERR.

133 Rule 5(1)(d) in Schedule 3 of the Retail Amending Rule.

- some stakeholders considered that a 12-month explicit informed consent period would provide sufficient time for customers to accumulate seasonal data [134]
- some stakeholders considered that the explicit informed consent period should be time-limited, and that three years was an appropriate duration [135]
- some stakeholders considered that an explicit informed consent right should endure and not be time-limited. [136]

We consider that a two-year explicit informed consent period is sufficient to allow consumers to accumulate seasonal data and make an informed decision about their retail tariff. Whilst we acknowledge that some stakeholders may prefer a longer explicit informed consent period, we consider that there are two key factors that will limit potential negative impacts associated with a shorter period than initially proposed:

1. Jurisdictions may choose to implement the new flat tariff requirement, detailed in section 3.3.3 below. If implemented, customers with a smart meter can still access a flat retail tariff structure at the end of their explicit informed consent period, should they prefer one.
2. The Commission's *Pricing review* will consider and make recommendations regarding ongoing pricing and tariff arrangements for customers across the NEM:
    a. the *Pricing review* is due to deliver its final recommendations in March 2026
    b. the explicit informed consent obligation will commence on 1 December 2025, meaning a customer that receives a new smart meter on this date will retain their explicit informed consent 'right' until 30 November 2027
    c. this allows over 18 months following the end of the *Pricing review* to progress and implement relevant recommendations, prior to the customer's explicit informed consent rights expiring.

DNSPs have varied approaches to network tariff reassignment following a smart meter deployment. We note that for DNSPs that have a transitional period between when a smart meter is installed and when a new network tariff is applied, the retailer will not face the new network tariff for a portion of a customer's two-year explicit informed consent period.

Implementation timing

This safeguard applies to all retail tariff variations resulting from a smart meter deployment from 1 December 2025, until the end of the acceleration program on 31 May 2031.[137] The acceleration program ends an additional six months after the conclusion of the LMRP period because it allows an additional six months for a small customer's legacy meter to be replaced under the program if the customer switches retailers during the final interim period.[138] This means that if a customer receives a smart meter at the very end of the program (for example, on 31 May 2031), the two-year explicit informed consent period will apply until 31 May 2033.

The 1 December 2025 start date aligns with the start date of the accelerated rollout, and is 11 months later than the 1 January 2025 start date proposed in the directions paper. In response to the directions paper, a range of stakeholders considered that a 1 January 2025 start date was infeasible due to the various process and system changes required to effectively implement a new explicit informed consent obligation. Some stakeholders considered that there should be a

134 Submissions to the directions paper: The Department for Energy and Mining (DEM), South Australia, Shell Energy
135 Submissions to the directions paper: Ausgrid, Clean Energy Council, Joint EWOs, the AER
136 Submissions to the directions paper: SA Vulnerable Networks Customer Advisory Group (VCAG), JEC, Joint COSSs, ECA
137 Rule 5(3) in Schedule 3 of the Retail Amending Rule.
138 Clause 11.177.7(b)(2) of the Electricity Retail Rule.

minimum six-month period between when the final rule is made and when a new explicit informed consent obligation commences. Others considered that the new explicit informed consent obligation should commence at the same time as the accelerated rollout. [139]

We acknowledge that implementing a new explicit informed consent obligation will require retailers to undertake various system and process changes, and that these could take time. We also acknowledge that retailers will be required to simultaneously deliver a range of other changes associated with the smart meter reforms outlined in this determination. Therefore, we consider that a 1 December 2025 start date is appropriate for the new explicit informed consent obligation.

3.3.3 The final retail rule requires designated retailers to make flat tariffs available to customers with a smart meter

Requiring designated retailers to make flat tariff offers available will enhance consumer choice

Requiring designated retailers to offer customers a flat tariff will support increased consumer choice in the competitive retail market, and better consumer outcomes.

This measure may particularly benefit consumers who cannot meaningfully shift their consumption to benefit from cost-reflective retail tariffs, such as tariffs with time-of-use and/or demand components. For example, some customers may reach the end of their two-year explicit informed consent period and find that a flat tariff best suits their needs, with these findings supported by their smart meter data.

Requiring designated retailers to make a flat tariff offer available also benefits consumers who find cost-reflective retail tariffs complex. Such customers may prefer a simple flat tariff product that they can easily understand and respond to.

Designated retailers must make flat tariff standing offers to customers with a smart meter, subject to implementation by jurisdictions

The final rule introduces an requirement for designated retailers to offer customers with a smart meter a flat retail tariff if it is implemented by adoptive jurisdictions through local instruments.[140] Retailers must only make this offer to customers for which they are the designated retailer.

Where this requirement has been introduced in a given jurisdiction and a small customer's meter is replaced, if a small customer's meter is replaced with a smart meter, then that customer's designated retailer must make a standing offer available to that customer with a flat retail tariff.[141]

The Commission has specific powers under section 22 of the NERL to make rules requiring designated retailers to offer customers with an interval meter (including smart meters) a certain tariff structure. These rules were implemented in 2013 through the *Statutes Amendment (Smart Meters) Act 2013*, following recommendations of the National Smart Meter Consumer Protection and Safety Review. This included a recommendation that consumers with a smart meter should be given an effective choice of retail tariff, including a standing offer flat tariff.

In accordance with the requirements of the NERL, jurisdictions need to opt into this new flat tariff requirement for it to come into effect.[142] That is, this rule only applies if and when a given adoptive jurisdiction declares that it applies in that jurisdiction through a local instrument.

139 Submissions to the directions paper: 1st Energy, ActewAGL, Alinta, EnergyLocals, EnergyAustralia, Joint EWOs, Red Energy, Shell Energy, AGL
140 Rule 4 in Schedule 3 of the Retail Amending Rule.
141 Rule 4(2) in Schedule 3 of the Retail Amending Rule.
142 Section 22(1a) of the NERL.

We note that on 19 September 2024, Queensland made a regulation requiring designated electricity retailers to make available a standing offer with a flat tariff structure.

We considered stakeholder feedback in making our final determination

In response to the directions paper, some retailers considered that our proposed consumer safeguards would impose unacceptable risks on their businesses, particularly in the context of historically low retail margins. These stakeholders noted that unlike wholesale price risks, which retailers seek to mitigate using specific financial risk management products such as caps and swaps, retailers do not have specific tools available to manage network cost risks. [143]

In our directions paper we noted that retailers may choose to take a portfolio approach to managing any cost risks associated with new consumer safeguards (that is, spreading costs across offers or their customer base). In response, some considered that while this approach may be available to larger retailers, smaller retailers may not be able to adopt it, given they may have fewer customers across a given network or tariff class to manage risk. Many retailers considered that instead of making changes to tariff arrangements at the retail-level, changes should be implemented at the network-level. [144]

Other stakeholders considered that whilst the proposed safeguards may have some adverse impacts on retailer businesses, retailers are in a better position to manage the risks associated with changes to tariffs than consumers, and therefore our additional protections are warranted. [145] Some stakeholders were strongly supportive of enhancing consumer protections, did not consider that there would be material risks for retailers, and considered that some retailers may in fact have scope to benefit. [146]

Consistent with our position in the directions paper, we do not consider that retailers will be uniformly worse off facing a network tariff that they cannot directly pass on to consumers. Whilst we acknowledge that retailer costs may increase for some customers, cost-reflective network tariffs will result in lower costs for other customers. In our directions paper we noted analyses in a number of DNSP TSSs which show that some customers will be better off (that is, experience a decrease in the network component of their bill) after moving from their existing flat network tariff to a cost-reflective tariff, even without assuming any behaviour change from the customer. [147]

We did not receive new supporting evidence in response to the directions paper from retailers that clearly demonstrated that retailer costs will increase for most or all customers.

3.4 Improving the customer experience in metering upgrades

Box 7: Final determination

4 Improving the customer experience	• helps maintain social licence for the acceleration program • ensures that customers can access the full suite of benefits that smart meters provide.

Supporting a positive customer experience in the acceleration program helps maintain social

143 Submissions to the directions paper: The AEC, 1st Energy, EnergyLocals, ENGIE, Next Business Energy, Origin Energy, Red Energy, Shell Energy, AGL.

144 Submissions to the directions paper: The AEC, 1st Energy, EnergyLocals, ENGIE, Next Business Energy, Origin Energy, Red Energy, Shell Energy, AGL.

145 Submissions to the directions paper: Joint EWOs, the AER.

146 Submissions to the directions paper: JEC, Joint COSSs.

147 Refer to directions paper (section 3.1.2).

licence for the reforms and ensures that customers can access the full suite of benefits that smart meters provide.

The final rules will:

- expand the smart meter information retailers must provide to customers prior to any upgrades
- enable customers to request a smart meter from their retailer for any reason, and require retailers to install a smart meter on receipt of such a request
- improve the meter malfunctions replacement framework by:
  - setting different timelines of 15 business days for individual meter malfunctions and 70 business days for family failure malfunctions identified through sample testing
  - improving the malfunctions exemptions process currently administered by AEMO, in its application to small customer metering installations.

3.4.1 The final retail rule will enhance information provided to customers before a meter upgrade

More information would inform and empower customers

In the context of an accelerated smart meter deployment, additional information will help customers better understand:

- their rights and responsibilities
- the importance of metering upgrades
- the benefits that smart meters offer, such as greater control of energy usage.

More information will also empower customers to make informed decisions throughout the accelerated deployment program.

The final retail rule requires retailers to provide customers with additional information before a smart meter upgrade

The final rule requires retailers to provide customers with written notice no more than 60 business days and no fewer than four business days before a proposed metering installation date.[148] Alternatively, the retailer can obtain the customer's explicit informed consent to the new meter installation or replacement occurring on any day within a date range of 5 business days or on a specified date.[149]

In the first case, the notice will include the information in Box 8, some of which is already required under the current rules.[150]Retailers will not be required to include customer-specific or bespoke information. Most of the information should apply to the retailer's broad customer base.

Box 8: Information that retailers must include in their notice to customers

- The reasons for the proposed meter deployment (for example, meter failure, customer request, or new meter deployment as defined in the NERR, rule 3).

148 Rule 59A(2)(a) of the Retail Amending Rule.

149 Rule 59A(2)(b) of the Retail Amending Rule.

150 The following information is currently required under rule 59A of the NERR: the expected date and time on which the retailer proposes to replace the customer's meter; 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.

- An indicative timeline for when the customer will receive the smart meter (this can be a date range of five business days).
- How the customer can access their smart meter data.
- The customer's rights and responsibilities regarding the meter installation (including remediation work).
- Any upfront charges the customer will incur under their retail contract as a result of the new meter deployment.
- Any changes to the consumer's retail contract resulting from the meter installation, including tariff changes (if applicable).
- A summary of the services available to the customer as a result of obtaining a smart meter (including how customers can benefit from smart meters).
- 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.

Retailers will issue the notice before all types of smart meter deployments, other than new connections. For example, customers who request a meter upgrade outside of the scheduled accelerated deployment program will receive a notice.

In the second case, where the retailer has obtained the explicit informed consent of the customer to the meter installation occurring within a date range or on a specified date, the following information will not be required to be included in the notice:[151]

- an indicative timeline for when the customer will receive the smart meter (this can be a date range)
- the customer's rights and responsibilities regarding the meter installation (including remediation work).[152]

We have made changes for the final rule in response to stakeholder feedback

In response to the draft determination, some stakeholders considered that there should be more flexibility in the notification requirements to allow for urgent replacements, such as for meter malfunctions. They also note that more flexibility would also allow retailers and metering parties to more efficiently allocate field resources – for example, where a metering provider is already in a local area and another customer requests a smart meter upgrade that day – and to meet customer expectations where the customer has already agreed on a replacement date with their retailer.[153]

The second case described above, which allows for the minimum four business day notification requirement to not apply if the retailer has obtained the customer's consent to the meter installation occurring within a 5 business day date range or on a specified date, provides this flexibility. If the retailer obtains the customer's consent, the retailer must issue a notice to the customer within five business days after the meter installation or replacement is undertaken.[154]

151 Rule 59A(4)(b) of the Retail Amending Rule.

152 The customer would have been informed of these information when they give their retailer explicit informed consent to installing a meter.

153 Submissions to draft determination: Red/Lumo, p. 2; PLUS ES, p. 11; AGL, p. 8; Momentum Energy, p. 2; Bluecurrent, p. 11.

154 Rule 59A(4) of the Retail Amending Rule.

We remind retailers of existing provisions in the NERR to assist customers affected by family violence.[155] For example, retailers must take reasonable steps to identify and use a safe method of communicating with customers. Once identified, this preferred method takes precedence over all other communication requirements in the retail rules.[156] The notice will be issued to customers via their preferred method of communication.

3.4.2 The final retail rule empowers customers to request and receive a smart meter for any reason

Expanding customer rights supports a better customer experience and more choice

An explicit provision granting customers the right to request and receive a smart meter for any reason:

- supports greater customer choice in product offerings, such as better access to energy usage data
- allows customers to have access to tariff options that may better suit their needs or preferences
- empowers customers to receive a smart meter should they wish to receive one, regardless of whether their current meter is functional.

The final retail rule requires retailers to install a smart meter for customers upon request

Under the current NERR, there is no explicit direction to retailers to install a smart meter for customer requests not associated with a connection upgrade or a solar PV installation.

The final rule gives customers without smart meters the right to request and receive a smart meter for any reason.[157] This includes where the customer:

- has a functioning legacy meter
- does not have CER installed at the premises.[158]

Retailers are required to fulfil any customer-initiated request within the existing installation timeline requirements in the NER.[159] This means that retailers will not be able to defer a customer-requested smart meter installation to the meter's scheduled replacement date under the LMRP if this is later than the installation timeline requirements under the NER.

The final electricity rule extends the existing timeframes for meter installations

In response to the draft determination, a range of stakeholders noted that there may be a higher-than-normal volume of customer requests for smart meters. These could come from customers seeking to access to benefits of smart meters early, rather than waiting for their retailer to initiate a deployment through the LMRP process. A high volume of customer-initiated requests could undermine retailers' ability to roll out smart meters in line with the LMRPs, given existing requirements on retailers to respond to such requests within a given period.

Some stakeholders also considered that the existing meter replacement timeline requirements are inappropriate for meter upgrades in regional or rural areas. This is due to potentially longer travel times for installers to attend a customer's site, and the likelihood of more limited installer resources in these areas.[160]

155 Part 3A of the NERR.
156 Rule 76H of the NERR.
157 Rule 59AA(1) of the Retail Amending Rule.
158 Non-CER customers are customers which do not own devices such as solar PV, battery energy storage systems, or electric vehicles.
159 Rule 59AA(2) of the Retail Amending Rule and clauses 7.8.10A to 7.8.10C of the NER.
160 Submissions to draft determination: Energy Queensland, p. 5; Origin, p. 7; AGL, p. 9.

In light of this feedback, we consider that it is appropriate to extend the timeframes for meter installations. For the final rule, existing installation timeline requirements under the NER will be extended by 5 business days for the duration of the LRMP period.[161] Excluding the malfunction timeline requirement, this means that:

- retailers must install meters within 11 business days for new connections, where an installation date is not agreed upon with the customer
- retailers must install meters within 20 business days where a connection service is not required, and an installation date is not agreed upon with the customer
- retailers must install meters within 20 business days where a connection alteration is required, and an installation date is not agreed upon with the customer.

3.4.3 The final electricity rule will improve the framework for replacing malfunctioning meters

A better malfunctioning meter framework will support faster replacements

Improving the framework to replace malfunctioning meters will reduce delays in meter replacements that could otherwise directly impact customer bills. A better framework will also support a more efficient allocation of resources and reduce administrative burden for market participants.

The final electricity rule makes a distinction between different types of malfunctions and introduces changes to the malfunctions exemption process

Under the final rule, there are two separately defined categories of meter malfunctions, with different replacement timeframes.[162] The replacement timeframe is from when the metering coordinator has been notified of the metering installation malfunction.

Table 3.1: Replacement timeframes for different malfunctions types

Malfunction category	Replacement timeframe
Individually identified (individual failures)	15 business days
Identified through statistical testing (family failures)	70 business days

These new timeframes differ from current arrangements where all types of malfunctioning meters must be replaced within 15 business days after the MC has been notified, or within 30 business days of the MC becoming aware the meter replacement involves interrupting supply to another customer (a shared fuse arrangement).[163] Under the final determination, if an MC finds that a malfunctioning meter is on a shared fuse, the MC will follow the process and timelines outlined in the proposed Shared Fusing Meter Replacement Procedure (per section 3.5.3).

The final electricity rule clarifies the malfunctions exemption process

Under current arrangements, where an MC cannot repair or replace the malfunctioning meter within the required timeframes, the MC may apply to AEMO for an exemption.[164] Information provided by AEMO states that as of April 2023, around 300,000 meters had been granted exemptions under AEMO's exemption framework, corresponding to approximately 4.4 per cent of NEM customers.

161 Clause 11.177.11 of Schedule 3 of the Electricity Amending Rule.
162 Clause 7.8.10(a)(2) of the Electricity Amending Rule.
163 Clause 7.8.10(a)(2) of the NER, version 217.
164 Clause 7.8.10(a) of the NER.

The final electricity rule creates a more clearly defined exemption process to support more timely replacements. When applying for an exemption, MCs will be required to provide AEMO with a rectification plan for malfunctions.[165] This is different to the current arrangements where the MC provides AEMO with a rectification plan after it receives an exemption.[166]

The current provision is a tier 2 civil penalty provision. The AEMC does not recommend changing this as the amended provision is substantially the same and should continue to be a civil penalty provision.[167]

The final rule also allows AEMO to amend and publish any procedures, guidelines and other documents that it considers necessary or desirable to amend to take into account this change to the malfunctions exemption process.[168] We anticipate AEMO will make changes to its procedure for malfunction exemptions. When updating its procedures, we expect AEMO to consider the size of any family failure (where applicable), as well as whether any previous exemptions have been granted.

The changes proposed to the malfunctions replacement process interact with other changes in the final rule

To clarify, MCs must still replace malfunctioning meters in accordance with time frame requirements under the NER, and not defer replacements to scheduled time frames under any LMRP.[169]

3.5 Reducing barriers to installing smart meters and improving industry coordination

Box 9: Final determination

5 Reducing installation barriers	• supports delivery efficiencies, and therefore cost savings, in the accelerated deployment of smart meters.

Reducing barriers and improving industry coordination will support delivery efficiencies, and therefore cost savings, in the accelerated deployment of smart meters.

The final rules:

- remove the option for customers to opt-out of a new meter deployment (as defined in the NERR, rule 3)
- reduce the number of notices that retailers send to customers before a new meter deployment from two to one
- establishe a process for DNSPs, retailers and metering parties to install meters in shared fusing scenarios, such as multi-occupancy sites
- enable a process for retailers to encourage customers to remediate, as well as to track customer defects at a metering installations.

165 Clause 7.8.10(c) of the Electricity Amending Rule.

166 Clause 7.8.10(c) of the NER.

167 See section C.5 of this final determination for more information on civil penalty recommendation.

168 Clause 11.177.13 of Schedule 3 of the Electricity Amending Rule.

169 Clause 7.8.10(e) of the NER.

3.5.1 The final retail rule removes customer opt-out provisions and encourages remediation of defects

The proposed opt-out changes will deliver a range of benefits

Removing customers' ability to opt-out of a smart meter upgrade will:

- reduce complexities in planning and executing the deployment of smart meters
- support the implementation of the Shared Fusing Meter Replacement Procedure described later in this Chapter, which relies largely on no customer opt-out
- achieve consistencies in customers' opt-out rights across different retail contracts
- mitigate the risk of customers indirectly incurring metering upgrade costs without access to the benefits of a smart meter.

Many stakeholders support the removal of opt-out provisions, noting this change will support accelerated deployment and universal uptake by 2030.[170] However, some stakeholders also note that complaints from customers who refuse a smart meter are likely to increase.[171]

The final retail rule removes opt-out provisions included in standard retail contracts

Under current arrangements, customers can opt out of a new meter deployment up to seven business days before the intended meter installation date.[172] Retailers are exempt from complying with these opt-out provisions if they are authorised to deploy a new meter under the terms of their customer market retail contract. This authorisation is not included in standard retail contracts.[173]

The final retail rule removes this provision in the NERR, which means customers on standard retail contracts will not be able to opt out of a new meter deployment.

Consistent with current arrangements, meters with remote access capabilities disabled (type 4A) are available to customers who refuse a smart meter where these capabilities are enabled (type 4).[174]

Removing opt-out provisions does not mean that customers must remediate defects at a metering installations

The Commission acknowledges that some customers may wish to opt out of a smart meter deployment to avoid any associated site remediation costs.

In the Review, the Commission recommended that governments consider financial support options to encourage remediation, particularly for vulnerable customers.

Remediation of a defect at a metering installation is currently the responsibility of the customer and beyond the scope of the energy laws and rules. 'Site defects' or 'defect at a metering installations' refer to meter board defects that prevent a meter installation. For example, this might include an inability to operate the supply isolation, insufficient space on the meter board, poor or damaged wiring, or asbestos in the meter board.

A customer cannot be compelled to remediate their defect at a metering installation and this is not affected by the change made in the final rule to remove the opt-out provisions. Therefore, under the final rule, customers retain the choice as to whether they remediate any defect at a metering installations.

170 Submissions to draft determination: EWO joint submission, p. 3; Master Electricians Australia, p. 3; PLUS ES, p. 10; Energy Queensland, p. 1; Alinta Energy, p.4; Intellihub, p. 2; AGL, p. 9; PIAC, p. 12.

171 EWO joint submission, submission to draft determination, p. 3.

172 Rule 59A(1) and (3) of the NERR.

173 Rule 59A(8) of the NERR.

174 Clause 7.8.4 of the NER.

3.5.2 The final retail rule reduces the number of retailer notices issued to customers before a meter upgrade

Streamlining notification requirements will improve customer experience and promote efficiency

A more streamlined notification process before a smart meter installation will:

- reduce the potential for customer confusion about the smart meter installation process
- support a more efficient smart meter installation process.

The final retail rule reduces the number of notices a retailer must provide

The final rule reduces the number of notices a retailer provides a customer prior to installing a new meter from two notices to one. These notice requirements are discussed more fully in section 3.4.1. The final rule requires retailers to provide customers with this single notice in writing or electronically.[175]

3.5.3 The final rules establish a Shared Fusing Meter Replacement Procedure (procedure) for meter upgrades on a shared fuse

The final electricity rule introduces a procedure for managing the replacement of meters with shared fusing.[176] Under this procedure, if shared fusing is identified at a premise, this triggers the upgrade of all legacy meters on the shared fuse at the same time– a 'one in all in' approach. This procedure applies where repairing, installing, or replacing a meter at the connection point of one customer requires interruption of supply to other small customers. The procedure is an ongoing provision and applies to all metering installations that do not have defects, site access issues, or site safety issues preventing installation.[177]

There are five key steps under the procedure

1. **Discovery of shared fusing:** An MC discovers meters on a shared fuse. Within five business days of discovery, the MC must contact the retailer that authorised the site visit and trigger the procedure. This party is referred to as the 'Original MC' under the procedure.[178]
2. **Raising a temporary isolation request:** Within five business days of being notified by the Original MC, the retailer must inform the relevant DNSP of the shared fuse. Retailers will raise a request for a TIGS, as per current arrangements.[179]
3. **DNSP notification to retailers:** Within 30 business days of being notified by the retailer, the DNSP must:[180]
    a. Identify all affected NMIs on a single shared fuse, which may require the DNSP to visit the site
    b. Either:
        i. where the number of legacy meters on the shared fuse is 10 or less, set a date and time for a supply outage to replace the meters, or
        ii. where the number of legacy meters on the shared fuse is greater than 10, set dates and times for the supply outages to replace the meters.

175 Rule 59A of the Retail Amending Rule.

176 Clause 7.8.10D of the Electricity Amending Rule.

177 Clause 7.8.10D of the Electricity Amending Rule.

178 Clause 7.8.10D of the Electricity Amending Rule.

179 As per current arrangements, retailers will need to request DNSPs to carry out a group supply interruption (i.e. a Distributor-Planned Interruption) if their supply interruption would impact any customers other than their own.

180 Clause 7.8.10D(c) of the Electricity Amending Rule.

The date(s) and time(s) of the supply outage/s under both scenarios are the date(s) and time(s) on which retailers and MCs must replace all legacy meters on a shared fuse. This must be between 25 and 65 business days after the notice is issued by the DNSP to the retailers.

c. Issue a notice to the retailers of the respective NMIs. The notice must include:[181]

   i. the details of the Original MC, which enables the retailer to appoint them as their MC for the site, should the retailer wish to do so

   ii. the date(s) and time(s) of the scheduled outage for the meter replacement

4. **Appointment of MCs:** Within 10 business days of receiving a notification from the DNSP, retailers must appoint an MC (the Original MC or one of their choosing) to replace the relevant legacy meters on the date(s) and time(s) specified in the DNSP's notification.[182]
5. **Meter replacement:** On the date and time prescribed in the notice and service order request, the DNSP undertakes the outage and the metering party or parties visit the site and install the new meters.

DNSPs will consider several factors in setting the date and time of a supply outage(s) or meter replacements

Under this procedure:

- DNSPs are not required to obtain customer EIC for a planned supply interruption unless it is a life support customer.
- Where a DNSP does not have a customer's EIC for a supply interruption, it must provide the customer a planned interruption notice at least four business days before the date of the interruption.[183]
- A DNSP may set more than one date and time where there are more than 10 meters on a single shared fuse that need to be upgraded and the circumstances require more than one day to replace all legacy meters.[184] The DNSP may consult with the Original MC or metering parties as to how many supply outage dates are required.
- The DNSP should consider the time reasonably required to install the new meters when setting a supply outage as per their existing obligations.[185]

We expect DNSPs, metering parties, and retailers to uphold the intent of this procedure and use their best endeavours to minimise the number of supply interruptions for all customers on a shared fuse.

DNSPs are responsible for providing customers with a planned interruption notice.[186]

We expect that the AER would allocate the cost of TIGS across impacted retailers on a pro-rata basis

We expect that the AER would require DNSPs to recover the cost of TIGS from all impacted retailers installing meters in the same TIGS event. This approach would strengthen the effectiveness of the procedure as it incentivises all retailers on the same fuse to coordinate their upgrades at the same time.

181 Clause 7.8.10D(c)(2) of the Electricity Amending Rule.

182 Clause 7.8.10D(e) of the Electricity Amending Rule.

183 Rule 90(1B) of the NERR.

184 Clause 7.8.10D(d) of the Electricity Amending Rule.

185 As per rule 90(3), a DNSP must use its best endeavours to restore the customer's supply as soon as possible in the case of a distributor planned interruption.

186 Rules 90 and 91A of the NERR.

Retailers that do not fulfil their obligations to organise a meter replacement during the TIGS event would need to raise a separate TIGS request to the DNSP, which would attract additional costs for those retailers. We consider that the AER has sufficient flexibility under the NER to give effect to the cost recovery of TIGS in this way. For example, through regulatory determinations.

The final retail rule increases the timeframes for DNSPs to meet their obligations under the procedure

In response to the draft determination, we received feedback from DNSPs that they need more time and flexibility to plan and manage group supply outages. They expect high volumes of outage requests for meter replacements and resourcing constraints during the acceleration period.[187] One DNSP noted that its network area has a high proportion of customers residing in multi-occupancy sites that may have shared fuses.[188]

Noting this feedback, under the final rule we have extended the timeframes for DNSPs to meet their obligations under the procedure:

- DNSPs have 30 business days, instead of 20 business days under the draft rule, to:
  - identify all NMIs on a single shared fuse
  - set the date(s) and time(s) of supply outages
  - issue a notice to the retailers of the respective NMI.

We consider that longer timeframes for DNSPs to meet their obligations will support flexibility whilst still ensuring that the benefits of the procedure are achieved.

The final retail rule considers life support customers

In response to the draft determination, some DNSPs considered that there should be flexibility in meeting particular customer needs, such as life support customers.[189]

The Commission considers that the procedure should be in line with existing protections relating to supply outages for life support customers. If a life support customer is involved in the single shared fuse, the DNSP must obtain explicit consent to the interruption on a specified date, consistent with existing arrangements.[190] If the DNSP cannot obtain the life support customer's explicit consent to the outage between 25 and 65 business days after the notice is issued, the DNSP should arrange the scheduled outage on an alternative date.

DNSPs need to provide non-life support customers prior notice of a supply interruption

For customers not on life support, including business customers, consent to supply outages is not required under this procedure. As such, DNSPs would need to provide these customers a notice of the supply interruption at least four business days before the interruption as per existing arrangements.[191]

Legacy meters on a shared fuse that are not affected by a defect at a metering installation must be replaced

There may be cases or types of defects at a metering installation where the defect does not affect all meters on a shared fuse. In these instances, meters not affected by the installation defect will

187 Submissions to draft determination: Essential, pp. 1,2; Endeavour, p. 6; Ausgrid, p. 7; SA Power Networks, p. 4; Evoenergy, p.2.

188 Submission to draft determination, Ausgrid, p. 7.

189 Submissions to draft determination: Energy Queensland, p. 11, Ausgrid, p. 7.

190 Rule 90(1)(c) of the NERR.

191 Rule 90 of the NERR.

be replaced under this procedure. Customers should not miss the opportunity to receive a smart meter if a defect at a metering installation does not prevent it from being installed.[192]

3.5.4 The final rules establishes a process to encourage customers to remediate and allows retailers to track defects at a metering installations

A defect notification and tracking processes will support the efficient deployment of more smart meters

As mentioned above, 'site defects' or 'defect at a metering installations' refer to meter board defects that prevent a meter installation, such as wiring issues. This does not include access issues or customer refusals of a smart meter. The final rules use the term 'defect at a metering installation'.[193]

Defects at a metering installation currently present a major barrier to smart meter installations. A formal remediation notice process with prompt reminders from retailers will encourage more customers who are willing and have the financial means to remediate. This will in turn enable the installation of more smart meters.

Establishing a formal defects-tracking process will provide a consistent source of information for industry on defects at a metering installations and increase deployment efficiencies through fewer wasted site visits.[194]

The final rules encourages site remediation and enables better tracking of defects

There are currently no clearly defined processes that market participants must follow when a meter upgrade is prevented by a defect at a metering installation.

The finalrules therefore establishes a customer notification and industry record-keeping process, which would be triggered when an MP encounters a defect on a site visit. The process set out in a new provision in the NERR and is an ongoing arrangement beyond the acceleration period.[195] It applies to all types of meter deployments.

MCs are responsible for identifying and recording defects, while retailers are responsible for notifying customers

1. **When an MP discovers a defect at a metering installation**
   - The MC must:[196]
     - notify the retailer of the defect
     - record the defect in MSATS, including the nature of defect, to minimise future wasted site visits.[197][198]

192 Metering parties may also need to consider and comply with jurisdictional metering installation requirements such as Service and Installation Rules.

193 See rule 59AAA(1)(a) of the Retail Amending Rule.

194 Energy Queensland, Intellihub and AGL raise there should be guidance or specification on what constitutes a site or defect at a metering installation and that there may be benefits in having standardised industry defect communications. We consider it more suitable that an industry body closely associated with providing metering services and technical standards develop this guidance or specification. For example, the Competitive Metering Industry Group. For the notification and tracking process for defects at a metering installation in this final rule, we consider defects at a metering installations to be issues with the physical metering installation on the customer's side that prevent a successful metering installation. For example, insufficient size of the meter board, wiring issues or asbestos.

195 Rule 59AAA of the of the Retail Amending Rule.

196 See amendments to rule 3 NERR and chapter 10 NER in Schedule 2 of the Retail Amending Rule and Schedule 1 of the Electricity Amending Rule, respectively.

197 The retailer and DNSP for a NMI will also have access to site defect information in MSATS.

198 Clause 11.177.12(a) of Schedule 3 of the Electricity Amending Rule.

- The retailer must, within five business days of being notified of a defect at a metering installation, send a notice to the customer informing them of the defect and requesting the customer remediate the site in preparation for a smart meter installation. [199]

2. **If the retailer has not received confirmation from the customer that the defect at a metering installation has been rectified within 40 business days of issuing the first notice:**[200]
   - The retailer must send a follow-up notice to the customer no less than 40 business days and no more than 45 business days after issuing the first notice to the customer
3. **The retailer must then use reasonable endeavours to confirm with the customer whether the defect at a metering installation has been rectified within 40 business days of issuing the second notice:**[201]
   - The retailer must use reasonable endeavours to contact the customer to confirm whether the site has been rectified.
   - We expect that the retailer will advise the MC where a defect has been rectified so that the MC may update the status of site remediation as successful in MSATS.
   - If the customer remediates their site and notifies the retailer, the retailer must progress the upgrade and replace the meter within the relevant timeframe under the NER.[202]
   - If the customer confirms with the retailer the defect at a metering installation has not been rectified, or if the retailer is not able to contact the customer, the retailer is not required to install the meter until they are notified that the defect at a metering installation has been rectified.

The final electricity rule requires that the MSATS Procedures include the information requirements above on defects at a meter installation.[203]

The final retail rule establishes a process to account for customers switching retailers or moving premises

In submissions to the draft determination, some stakeholders noted that the draft rule does not account for the scenario where the customer residing at a given premises changes (customer churn). They considered that in such scenarios, the defect notification process should restart, so that retailers issue two notices.[204]

Stakeholders also considered that retailers should issue two notices, when the customer switches retailer (i.e. retailer churn), This is so customers receive consistent notices from their retailer.[205]

We agree with stakeholders that requiring two notices in the above circumstances will help ensure that all customers are:

1. aware of defects at their premises
2. provided the opportunity to remediate the defect, so they may receive a smart meter.

We have therefore introduced changes to what was included in the draft rule.

Under the final retail rule, where the customer switches retailers (retailer churn) and where a customer at a premise changes (customer churn), retailers must provide the customer with two

199 Rule 59AAA(1)(b) of the Retail Amending Rule.
200 Rule 59AAA(1)(c) of the Retail Amending Rule.
201 Rule 59AAA(1)(d)(e)(f) of the Retail Amending Rule.
202 Clause 7.8.10A, 7.8.10B, 7.8.10C or 7.8.10D of the NER.
203 Clause 11.177.12(a) of Schedule 3 of the Electricity Amending Rule.
204 Submissions to draft determination: Bluecurrent, p. 10; PLUS ES, p. 18; AGL, p. 11; Origin, p. 2.
205 Submissions to draft determination: PLUS ES, p. 18; AGL, p. 11.

defect notices.[206] Retailers must issue the defect notices when they become aware of the defect at a metering installation, in line with the timeframes of this notice procedure for defects at a meter installation.[207] In effect, this means that the retailer restarts the process.

The final rule does not require retailers to record the date of the defect notice in MSATS

In response to the draft determination, several retailers and metering parties considered that requiring retailers to record the date of the defect at a metering installation in MSATS would be costly relative to likely benefits.[208] Following this feedback, we have not included the requirement for retailers to record the date of defect notices in MSATS in the final rule.

Only the MC is required to record site defect information in MSATS, including in multi-occupancy scenarios

In some scenarios, an Original MC may identify a defect at a metering installation that impacts other NMIs at a shared fusing site. The Original MC can only record site defect information in MSATS for NMIs or meters to which they have been appointed by the retailer ie, not for the other NMIs or meters for which they do not have a financial role. In response to the draft determination, some stakeholders considered that a single party should record the defect at a metering installation for all impacted meters or NMIs at a shared-fusing site. They considered that this single party could be the DNSP, as it has an interest in all NMIs or meters on the shared-fuse, or the Original MC. They considered that this would reduce wasted site visits and costs, and support further efficiencies.[209]

Some stakeholders noted that without access to NMI Discovery, the Original MC cannot update MSATS for impacted NMIs to which they are not appointed.[210] Some stakeholders considered that the DNSP could be the appropriate party to record this information in MSATS, as the common market participant across all NMIs.[211]

Consistent with the draft determination, under this final determination, only the MC is required to record defect information in MSATS, and only for meters to which they are appointed. This is because:

- requiring other parties (such as the DNSP) to also record site defect information in MSATS would have material implementation costs due to new system builds or changes to current system capabilities, including MSATS and B2B procedures.
- we do not consider that MCs should have access to a customer's NMI Standing Data unless they are appointed as the MC for a given connection point.

We consider that the appointed MC, which has a direct financial interest in the meter, is the only party appropriately incentivised to accurately identify and record defect information about that meter.

The final electricity rule requires the nature of the defect to be recorded in MSATS

In response to the draft determination, we received stakeholder feedback that the nature of the defect at a metering installation should be included in MSATS. Stakeholders considered that this would have a range of benefits including:[212]

206 Rule 59AAA(2) and (3) of the Retail Amending Rule.

207 Rule 59AAA(2) of the Retail Amending Rule.

208 Submissions to draft determination: AEC, p. 2; AGL, p. 11; Origin, 7; PLUS ES, p. 18; Energy Queensland, p. 13; Bluecurrent, p. 10.

209 Submissions to draft determination: Energy Queensland, p. 13; EnergyAustralia, p. 4; PLUS ES, p. 18-19; Origin, p. 2.

210 Submissions to draft determination: PLUS ES, p. 18; Bluecurrent, p. 12.

211 Submissions to draft determination: PLUS ES, p. 11; EnergyAustralia, p. 4.

212 Submissions to draft determination: PLUS ES, p. 14 and 30; Bluecurrent, p. 2 and 10; Energy Queensland, p. 12.

- **efficiency and cost-effectiveness** — using MSATS is the most efficient and cost-effective way to record and communicate this information between metering parties and retailers
- **better information for customers** — customers would be better informed about the type of defect and what needs to be done to resolve it (for example, engaging an electrician)
- **lower implementation work and costs** — using MSATS to record defect information would avoid requiring additional B2B procedures to communicate this information between metering parties and retailers.

We agree with these stakeholders. Customers should be supported and informed about their defect at a metering installation so they can make a well-informed decision on the next steps to rectify it if they choose to do so. Centrally recording site defect information via MSATS will also allow for more efficient information-sharing among market participants, such as in instances of retailer churn.

The final electricity rule classifies information on defects at a metering installation as NMI Standing Data.[213] This means that this information can be recorded in MSATS.

With respect to recording the nature of defects, we understand AEMO will need to consider implications to ensure its compliance with Protected Information requirements and the Privacy Act.[214] We consider that AEMO is best placed to manage these implications through its MSATS Procedures.

We suggest recording the nature of the defect in MSATS using only predefined fields or codes that market participants must select, rather than free text inputs. This would prevent market participants from sharing sensitive information. We consider that AEMO and industry, particularly metering parties, are well-placed to work together to determine the name, code and/or meaning of the predefined fields.

3.6 Creating a fit-for-purpose testing and inspection regime

Box 10: Final determination

6 Improved meter testing & inspections

- helps minimise costs for industry and customers
- supports a 2030 universal smart meter deployment target.

A fit for purpose meter testing and inspection framework will help minimise metering costs for industry and consumers and support a 2030 universal accelerated deployment target. The final electricity rule:

- exempts MCs from testing and inspecting legacy meters during the LMRP period.
- clarifies the testing and inspection requirements for meters by:
    - refining how the testing requirements apply
    - requiring MCs to inspect smart meters in line with an asset management strategy (AMS) approved by AEMO
    - requiring AEMO to develop, maintain, and publish guidelines on the AMS submission and approval process.

213 See amended definition of 'NMI Standing Data' in Schedule 1 of the Electricity Amending Rule.

214 Submissions to draft determination, AEMO, p. 2.

3.6.1 The final electricity rule will tailor testing and inspection requirements for legacy meters during the LMRP period

Temporarily exempting legacy meters from testing and inspection will reduce costs

Under the proposed LMRP process outlined in section 3.1, legacy meters will be progressively replaced with smart meters across the NEM between 2025 and 2030. Temporarily exempting MCs from testing and inspecting these legacy meters during this period avoids unnecessary costs for maintaining meters that are soon to be replaced.

The temporary nature of the exemption mitigates the risk of any ongoing customer bill impacts from any inaccuracies and impairments of legacy meters if they are not replaced during the LMRP period.

The final electricity rule will temporarily exempt MCs from testing and inspecting legacy meters during the LMRP period

Under current arrangements, Schedule 7.6 of the NER sets out the default level of testing and inspection for each meter category in terms of a maximum period between tests and inspections. MCs can also outline an alternative testing and inspecting practice for meters in an AMS, subject to AEMO's approval.[215]

The final electricity rule exempts MCs from testing and inspecting all legacy meters during the LMRP period.[216] The testing and inspection requirements for legacy meters will re-apply after the LMRP period ends.[217]

MCs will not be permanently exempted from testing legacy meters

In response to the draft determination, several stakeholder submissions requested we consider testing and inspection arrangements for legacy meters after the end of the LMRP period.[218] This included proposals to exempt MCs from legacy meter testing and inspection permanently,[219] to transfer responsibility of legacy meters from DNSPs to retailers,[220] and to decommission the legacy meter testing and inspection framework.[221] Stakeholders suggested that testing and inspecting a small number of legacy meters, which may be geographically widespread or remote, would increase costs and inefficiencies with minimal corresponding benefit.[222] Given the AER approved in its 2024-29 revenue determinations for a depreciation of DNSP metering asset bases to zero or near zero by 2029, stakeholders also suggested it is not consistent with these determinations to have to test and inspect legacy meters.[223]

We consider that the AMS is the best mechanism to determine the appropriate ongoing legacy meter testing and inspection approach. Therefore, we have not included the additional changes proposed by stakeholders in our final rule. The testing and inspection framework in the NER requires MCs to test and inspect legacy meters in line with an AMS approved by AEMO. The AMS gives stakeholders responsible for legacy meters with the flexibility to design their testing and

215 See 'Maximum Period Between Tests' in Table S7.6.1.2 and 'Period Between Inspections' in Table S7.6.1.3 in Clause S7.6.1 of the NER.

216 Clauses S7.6.1.2(b) and S7.6.1.3(b) of the Electricity Amending Rule.

217 For clarity, the testing and inspection exemption applies only to routine testing and inspection, and not to testing and inspection mandated under any schemes with jurisdictional Energy and Water Ombudsmen.

218 Submissions to draft determination: AGL, p. 12; ENA, p. 2; Endeavour Energy, pp. 132-14; Essential Energy, p. 2; Energy Queensland, p. 13; Evoenergy, p. 3; PIAC, pp. 13-14; PLUS ES, p. 20; SA Power Networks, p. 5; TasNetwork, pp. 3-4.

219 Submissions to draft determination: AGL, p. 12; Ausgrid, p. 10; PLUS ES, p. 20; SA Power Networks, p. 5; Tas Networks, pp. 3-4.

220 Submissions to draft determination: Essential Energy, p. 2; Endeavour Energy, p. 14.

221 AGL, submission to draft determination, p. 12.

222 Submissions to draft determination: Ausgrid, p. 10; AGL, p. 12; Endeavour Energy, pp. 12-13; Essential Energy, p. 2; TasNetwork, pp. 3-4; PLUS ES, p. 20; SA Power Networks, p. 5; ENA, p. 2; PIAC, p. 13.

223 Submissions to draft determination: Endeavour Energy, p. 14; Essential Energy, p. 2.

inspection strategies for remaining legacy meters across the NEM, subject to AEMO's approval. The testing and inspection objective, principles and associated guideline in the final rule also allow AEMO to give stakeholders additional clarity in this regard.

Section 3.6.2 of this final determination provides further detail on the new testing and inspection objective and principles, and the contents of the new testing and inspection guidelines.

3.6.2 The final electricity rule clarifies meter testing and inspection requirements

Clearer meter testing and inspection requirements will reduce metering costs

The Review identified that current meter testing and inspections requirements are unclear and can give rise to different interpretations, which creates uncertainty. The lack of clarity on the requirements can ultimately lead to onerous and inefficient testing and inspection outcomes. These inefficiencies can have cost impacts for energy customers, who ultimately meet the costs of metering services.[224]

Clear meter testing and inspection requirements will help achieve the full benefits of a faster deployment. The final rule:

- promotes more efficient testing and inspection practices
- enables a more cost-effective approach to meter inspection
- supports confidence in the accuracy of NEM data
- provides flexibility in a changing NEM, with fit for purpose guidelines that can be updated by AEMO in response to changing factors.

The new AMS guidelines will give MCs more clarity on what is included in an AMS, and the AMS submission and approval process. Additionally, using guidelines rather than prescriptive requirements ensures that inspection standards remain fit for purpose in changing circumstances. For example, the *Unlocking CER benefits through flexible trading rule* has introduced a new category of minor energy flow meters.[225] These meters will likely need different or more flexible testing and inspection requirements.

The final electricity rule supports recent changes to testing and inspection requirements

The *Unlocking CER benefits through flexible trading rule* recently made changes to clarify meter testing and inspection requirements. These changes overlap with some proposed changes in the proposal for this rule change. Therefore, our final rule:

- does not progress a change to clarify that the testing requirements for whole current meters only apply to the testing, and not inspection, of meters. The Unlocking CER Benefits final rule made this change, which commenced on 29 August 2024.[226]
- requires MCs to inspect whole current and non-whole current legacy and smart meters in accordance with an AEMO-approved AMS from 1 December 2025.[227] This will remove the ambiguity around the inspection requirements for legacy and smart meters until changes to these requirements under the Unlocking CER benefits final rule commence on 31 May 2026. The Unlocking CER benefits final rule will distinguish between the default inspection time frames for whole current and non-whole current legacy and smart meters.[228]

224 AEMC, Review final report, pp. 155-158.

225 AEMC, *Unlocking CER benefits through flexible trading*, https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading.

226 See clause S7.6.1 in item 2 of Schedule 1 of the NER (Unlocking CER benefits through flexible trading) Rule 2024 No. 15.

227 See changes to Table S7.6.1.3 in item 15 of Schedule 1 of the Electricity Amending Rule. Note: If there is an LMRP in place for a legacy meter, MCs would be temporarily exempt from testing and inspection legacy meters under the final rule (see section 3.6.1).

228 See changes to Table S7.6.1.3 in item 30 of Schedule 2 of the NER (Unlocking CER benefits through flexible trading) Rule 2024 No. 15.

- removes the requirement for whole current meter testing and inspection AMS guidelines to be recorded in the metrology procedures.[229] This is consistent with our final rule and gives AEMO the flexibility to decide the most appropriate location for the guidelines.

The final electricity rule requires AEMO to develop, maintain, and publish new AMS guidelines

The final electricity rule requires AEMO to develop, maintain, and publish new guidelines regarding how an AMS should be developed by MCs and approved by AEMO.[230]

Under the final rule, the AMS guidelines will describe:

- the information MCs must include in an AMS and that AEMO will make available during the AMS approval process
- the process for submitting an AMS to AEMO for approval and the relevant assessment time frames
- AEMO's AMS approval criteria.[231]

The initial AMS guidelines must be published by 1 July 2025.[232] The guidelines should be developed in accordance with the Rules consultation procedures in the NER.[233] AEMO may amend the AMS guidelines from time to time,[234] and make minor or administrative amendments:

- if the AMS guidelines are a standalone document then they do not need to comply with the Rules consultation procedures
- if the AMS guidelines are included in one of AEMO's procedures then they are subject to the Rules consultation procedures.[235]

The final electricity rule introduces a testing and inspection objective and associated principles

To support AEMO in developing the AMS guidelines, the final electricity rule introduces an asset management strategy objective and associated high-level principles to be taken into account when making and amending the AMS guidelines.[236]

Box 11: AMS objective

The objective of an AMS is for MCs to have a testing and inspection strategy in place to reliably test metering installation accuracy and identify metering installation condition faults in a reasonable period.

A clear objective reduces ambiguity in the testing and inspection requirements by making it easier to discern whether a testing and inspection strategy meets the intent of Schedule 7.6.[237]

Currently, the NER only provides a list of checks that inspection 'may include'.[238]

229 See changes to Table S7.6.1.2 in item 13 of Schedule 1 and Table S7.6.1.3 in item 1 of Schedule 3 of the Electricity Amending Rule.

230 Clause S7.6.1(g) of the Electricity Amending Rule.

231 Clauses S7.6.1(h)(1)-(3) of the Electricity Amending Rule.

232 Clause 11.177.14 of the Electricity Amending Rule.

233 Clause S7.6.1(g) of the Electricity Amending Rule.

234 Clause S7.6.1(i) of the Electricity Amending Rule.

235 Clause S7.6.1(j) of the Electricity Amending Rule.

236 Clauses S7.6.1(k), S7.6.1(l)(1)(i)-(ii) and S7.6.1(l)(2) of the Electricity Amending Rule.

237 The objective in the Electricity Amending Rule does not include the reference to 'have regard to the costs and benefits to consumers', which was proposed in the draft Electricity Amending Rule. We consider the reference to be unnecessary because MCs use an AMS to propose more efficient and cost-effective testing and inspection strategies that meet the intent of Schedule 7.6 of the NER. AEMO also has regard to the NEO when assessing proposed asset management strategies.

238 Clause S7.6.2(f) of the NER.

High-level principles will demonstrate how the AMS guidelines promote efficiency and allow flexibility and innovation in testing and inspection practices. The principles could also address MCs' concerns about overly specific testing and inspection requirements, which hinder metering competition.

The final rule also defines key terms such as AMS, AMS guidelines, legacy meter, and LMRP which are necessary to support the operation of the testing and inspection amendments.[239]

239 New definitions in Electricity Amending Rule.

A Rule making process

At a minimum, a fast-track rule change request includes the following stages:

- a proponent submits a rule change request
- the Commission initiates the rule change process
- the Commission publishes a draft determination and draft rule (if relevant)
  - stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

You can find more information on the rule change process on our website.[240]

A.1 Intellihub, SA Power Networks and Alinta Energy submitted a rule change request to enable the aceclerated deployment of smart meters and unlock their benefits

The rule change request submitted by the proponents seeks to implement the Review recommendations to enable a faster, more efficient, and more effective deployment of smart meters across the NEM, and to unlock their benefits for all stakeholders, particularly consumers. Specifically, the rule change request seeks to:

- achieve universal deployment of smart meters across the NEM
- reduce barriers to installing smart meters and improve industry coordination
- improve the customer experience and customer safeguards in the transition to smart meters
- enable better access to PQD from smart meters
- create a fit for purpose meter testing and inspection regime.

A.2 The proposal identifies several inefficiencies in the existing metering regulatory framework

The proposal states that smart meters are a key enabler of the transition of the energy system in that their data is necessary for a faster transition to net zero. It also states that the data and services smart meters provide may enable more affordable electricity services and improved system security and safety.

The proposal suggests that without changes to the existing metering regulatory framework, NEM customers may not receive smart meters until the late 2030s, or later.

The proposal identifies issues with the current framework governing metering, including:

- the deployment of smart meters has been too slow
- information provided to customers in the smart meter transition has been too limited
- there are the barriers and costs in the metering installation process that should be removed
- access arrangements for the PQD from smart meters are not fit for purpose
- unclear meter testing and inspection requirements impose unnecessary costs.

240 See our website for more information on the rule change process: https://www.aemc.gov.au/our-work/changing-energy-rules

A.3 The proposal would address these inefficiencies to improve the metering regulatory framework

The proposal suggests amendments to the NER and NERR to improve the metering regulatory framework to facilitate the accelerated deployment of smart meters (see Table A.1).

Table A.1: Summary of proposed amendments

Proposed Amendment	Details
Achieve universal smart meter deployment	• Sets a target and creates a mechanism to replace legacy meters with smart meters across the NEM by 2030, through a new LMRP mechanism.
Reduce barriers to installing smart meters and improve industry coordination	• Implements a 'one-in-all-in' meter installation process for multi-occupancy scenarios with shared-fusing. • Creates a process for managing site defects, removing the option for customers to opt-out of the smart meter deployment. • Reduces the number of notices for customers before new meter deployment. • Improves the meter malfunctions framework.
Improve the customer experience and safeguards	• Requires additional information to be included in notices to customers about the deployment and associated tariff changes. • Allows customers to request smart meters from retailers for any reason.
Enable better access to PQD	• Introduces arrangements to enable DNSPs to better access to PQD without cost or delay, and on an ongoing basis.
Create a fit for purpose testing and inspection regime	• Exempts MCs from the testing and inspection of legacy meters if an AMS has not been approved. • Clarifies meter testing and inspection requirements. • Requires AEMO to develop AMS guidelines.

Source: Rule Change Request submitted by Intellihub, SA Power Networks, and Alinta Energy.

A.4 The process to date

On 14 March 2024, the Commission published a notice advising of its intention to initiate the rule making process in respect of the rule change request.[241] The Commission decided to fast-track this rule change request. This is because it concluded that the rule change request is consistent with relevant recommendations made by the Commission in the Review and adequate

241 This notice was published under section 95 of the NEL and section 251 of the NERL.

consultation with the public was undertaken during that review on the relevant recommendations.[242]

Accordingly, the Commission published a draft rule determination on 4 April 2024 without first publishing a consultation paper. The Commission received 151 submissions on the draft rule determination. Issues raised in submissions are discussed and responded to throughout this final rule determination. A summary of other issues raised in submissions and the Commission's response to each issue is contained in Appendix E.

In response to the draft determination, a broad range of stakeholders acknowledged the critical role that smart meters will play in the future energy system. However, stakeholders also raised concerns regarding negative customer experiences following a smart meter installation due to retail tariff variations. These stakeholders considered that we should strengthen the existing consumer safeguards package proposed in our draft determination.

Noting these concerns, we published a directions paper on 15 August 2024, to consult further on potential enhancements to consumer safeguards for the accelerated smart meter rollout. We received 37 submissions in response to the directions paper.

Submissions received in response to the draft determination and directions paper have informed this final rule determination.

242 The decision to fast-track the rule change request was made under section 96A(1)(b) of the NEL and section 253(1)(b) of the NERL.

B Regulatory impact analysis

The Commission has undertaken regulatory impact analysis to make its final determination. This analysis draws on the cost-benefit analysis that the Commission undertook in the Review.[243] It also accounts for recent emissions amendments to the NEO and NERO, which came into effect after the Review concluded.[244]

As part of the Review, the AEMC engaged independent consultants Oakley Greenwood to assess the economic costs and benefits of the accelerated deployment of smart meters.[245]

Box 12: Independent cost-benefit analysis by Oakley Greenwood

Oakley Greenwood's cost benefit analysis of the accelerated deployment of smart meters showed that the accelerated deployment would have significant net benefits compared to the current 'new and replacement' metering framework. Most stakeholders considered the cost-benefit analysis to be robust and agreed it provided a strong basis for the 2030 target included in this final determination.

For the final report of the Review, the Commission engaged Oakley Greenwood to undertake further sensitivity analysis for potentially higher metering costs than those considered in the initial cost-benefit analysis. Oakey Greenwood found that the net benefits of acceleration remained positive, although smaller, in the higher cost scenario.

For more on the Commission's assessment of the costs and benefits of each policy option, see the Review's final report.

B.1 Our regulatory impact analysis methodology

B.1.1 We considered a range of policy options

The cost-benefit assessment compared a range of viable policy options that are within the AEMC's statutory powers. Oakley Greenwood modelled the costs and benefits of the following options:[246]

- business-as-usual—that is, no changes to the NER and NERR
- accelerated deployment reaching 100 per cent smart meters by 2030
- accelerated deployment reaching 100 per cent smart meters by 2032.

B.1.2 We assessed the benefits and costs of each policy option

The final determination is to make a rule for accelerated deployment targeting universal uptake of smart meters by 2030. The Commission is satisfied this is in the long-term interests of consumers, for the reasons set out in the Review and below.[247]

In making its final determination, the Commission relied on qualitative and quantitative methodologies applied in the Review to assess each policy option. The depth of analysis was commensurate with the potential impacts.[248]

243 AEMC, Review final report.

244 Amendments to the national energy objectives took effect on 21 September 2023.

245 Oakley Greenwood, *Costs and Benefits of Accelerating the Rollout of Smart Meters*, September 2022, https://www.aemc.gov.au/sites/default/files/2023-08/oakley_greenwood_cba_report_-_september_2022.pdf; Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, August 2023, https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_addendum_to_oakley_greenwood_cba_-_higher_meter_cost_sensitivity_-_august_2023.pdf.

246 AEMC, Review final report, p. 163.

247 Ibid, p. 164.

248 Ibid.

In the cost-benefit analysis for the Review, Oakley Greenwood only included those benefits for which quantitative modelling was feasible and proportionate to the potential impacts. However, the Commission considered a broader range of costs and benefits in the Review as a whole. These broader costs and benefits have informed our final determination.[249]

Leveraging the outputs of the quantitative cost-benefit assessment, the Commission identified impacts on different stakeholders — in particular, consumers — and considered the costs and benefits for each.[250]

B.1.3 We tested the sensitivity of cost-benefit results to higher metering costs

Following the Review's draft report, the Commission engaged Oakley Greenwood to undertake sensitivity analysis of the impacts of higher metering costs than those initially modelled.[251]

The Commission considered that it would be prudent to test a scenario where metering costs were significantly higher than those assumed in the Review's draft report, noting that metering cost assumptions are key inputs into the model. Multiple sources of information can 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. [252]

Oakley Greenwood's sensitivity analysis showed that the net benefits of acceleration are still positive, albeit reduced, in higher metering cost scenarios:

- if both of the estimated 'contingent benefits' (tariff impacts and quicker restoration) are omitted, the net benefits remain positive or neutral for all states considered.[108]
- if just tariff impacts are omitted, the net benefits remain positive for all states considered.[253]

B.1.4 Our cost-benefit analysis accounted for the NEO and NERO

The AEMC used Oakley Greenwood's cost-benefit analysis to support our assessment of the rule change against the following criteria:

- improve consumer outcomes
- support market efficiency
- promote innovation and flexibility
- support emissions reduction
- address implementation considerations.

These assessment criteria reflect the key potential impacts — costs and benefits — of the rule change request, for impacts within the scope of the NEO and NERO.

For more on the assessment framework for this rule change, see Chapter 2.

B.1.5 We also accounted for recent changes to the NEO and NERO which require the AEMC to consider greenhouse gas emissions

In September 2023, the national energy laws were amended to incorporate emissions reduction into the national energy objectives under the Emissions Act.[254] This change brings jurisdictional

249 Ibid.

250 Ibid

251 Ibid, p. 168.

252 Ibid.

253 Oakley Greenwood, *Sensitivity Analysis of Higher Meter, Installation and Other Costs*, August 2023, https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_addendum_to_oakley_greenwood_cba_-_higher_meter_cost_sensitivity_-_august_2023.pdf.

254 The amendments took effect on 21 September 2023.

emissions reduction targets (or other jurisdictional targets that would contribute to emissions reduction) within the scope of the national energy framework.[255] It means emissions reduction is now an explicit and relevant consideration in market bodies' decision-making, such as the AEMC's regulatory impact analysis for rule changes.

The Commission expects the accelerated deployment of smart meters will support emissions reduction in the electricity sector, for the reasons discussed below. Consequently, we are satisfied the acceleration of smart meters remains in the long-term interest of consumers under the updated NEO and NERO.

Smart meters support the integration of zero or low emissions technologies. Behind the meter, smart meters support increased reliance on CER such as solar PV, battery energy storage systems and electric vehicles. In the wholesale market, smart meters facilitate more flexible demand response. This supports increased reliance on variable renewable generation.

A further, minor, emissions consideration in favour of accelerated deployment is the reduction in transport emissions from site visits to read/inspect accumulation meters due to the accelerated deployment of remotely-read smart meters.

255 Under the updated NEL and NERL, the AEMC is required to maintain and update a targets statement that contains a list of all emissions reduction targets set by jurisdictions for reducing Australia's greenhouse gas emissions and targets that are likely to contribute to reducing emissions. The targets statement is available at https://www.aemc.gov.au/regulation/targets-statement-emissions.

C Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL and NERL for the Commission to make a final rule determination.

C.1 Final rule determination and final rules

In accordance with section 99 of the NEL and section 256 of the NERL, the Commission has made this final rule determination in relation to the rule proposed by Intellihub, SA Power Networks and Alinta Energy.

The Commission's reasons for making this final rule determination are set out in Chapter 2.

The Commission has made a final electricity rule and a final retail rule (the final rules). A copy of the final rules are attached to and published with this final determination. The key features are described in Appendix D.

C.2 Power to make the rules

The Commission is satisfied that the final rules fall within the subject matter about which the Commission may make rules.

The final electricity rule falls within:

- section 34(1)(a)(iii) of the NEL, the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system.
- section 34(1)(aa) of the NEL, facilitating and supporting the provision of services to retail customers.

The final retail rule falls within:

- section 237(1)(a)(i) of the NERL as it relates to the provision of energy services to customers, including customer retail services and customer connection services.
- section 237(1)(a)(ii) of the NERL as it relates to the activities of persons involved in the sale and supply of energy to customers.

C.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL and NERL to make the final rules
- the rule change request
- the Commission's analysis as to the ways in which the final rules will or are likely to contribute to the achievement of the NEO and NERO
- the application of the final rules to the Northern Territory
- submissions to the draft determination and directions paper
- the extent to which the final retail rule is compatible with the development and application of consumer protections for small customers.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[256]

C.4 Making electricity rules in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[257] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

As the final rules relates to parts of the NER that apply in the Northern Territory, the Commission is required to assess Northern Territory application issues, described below.

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[258]

1. The national electricity system
2. One or more, or all, of the local electricity systems[259]
3. All of the electricity systems referred to above.

Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[260] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[261]

In developing the final electricity rule, the Commission has considered the application to the Northern Territory according to the following questions:

- Should the NEO test include the Northern Territory electricity systems? Yes. The Commission considers that the NEO test should include the Northern Territory electricity systems given that the final rule will apply in the Northern Territory (even though it will have no practical effect).

256 Under s. 33 of the NEL and s. 73 of the NGL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. In December 2013, it became known as the Council of Australian Government (COAG) Energy Council. In May 2020, the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting were established to replace the former COAG Energy Council.

257 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016

258 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

259 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

260 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

261 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

- Should the rule be different in the Northern Territory? No. The Commission's final rule is a uniform rule because the Commission does not consider it appropriate for the final rule to be different in the Northern Territory.

C.5 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to the Energy Ministers' Meeting that new or existing provisions of the NER or NERR be classified as civil penalty provisions or conduct provisions.

The NEL and NERL set out a three-tier penalty structure for civil penalty provisions in the NEL, the NER, the NERL and the NERR.[262] A Decision Matrix and Concepts Table, approved by Energy Ministers, provide a decision-making framework that the Commission applies, in consultation with the AER, when assessing whether to recommend that provisions of the NER or NERR should be classified as civil penalty provisions, and if so, under which tier.[263]

The final electricity rule includes three new provisions in the NER, which the Commission proposes to recommend to the Energy Ministers' Meeting be classified as civil penalty provisions, as set out below.

Table C.1: NER civil penalty provision recommendations

Clause	Description of clause	Proposed classification	Reason
7.8.10D(e)	This clause requires retailers, within 10 business days of receiving a Shared Fusing Meter Replacement Notice from the LNSP, to appoint an MC to replace the relevant metering installations on the Shared Fusing Meter Replacement Date.	Tier 2	Failure by retailers to appoint MCs to replace meters on the Shared Fusing Meter Replacement Date will lead to additional supply outages for customers and would lead to additional costs being incurred, which would be passed on to consumers. This Tiering is also consistent with other similar CPPs in Chapter 7 of the NER.
7.3.2(k)	This clause requires Metering Coordinators to provide power quality data from small customer metering installations to the persons referred to in clause 7.15.5(c2) and in accordance with the procedures authorised by AEMO under Chapter 7.	Tier 2	Failure to provide this information to the appropriate parties would negatively impact the energy system, given this information would enhance the management of the distribution network. This Tiering is also consistent

262 Further information is available at https://www.aemc.gov.au/regulation/energy-rules/civil-penalty-tools.

263 The Decision Matrix and Concepts Table is available at: https://web.archive.org.au/awa/20210603104757mp_/https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Final%20-%20Civil%20Penalties%20Decision%20Matrix%20and%20Concepts%20Table_Jan%202021.pdf.

Clause	Description of clause	Proposed classification	Reason
			with the corresponding obligation on Metering Data Providers to provide metering data and NMI standing data.
11.177.7	This clause requires retailers to: (a) ensure that all Legacy Meters at connection points for which it is the financially responsible Market Participant at the Replacement Deadline are replaced no later than the Replacement Deadline, unless the Affected Retailer has a reasonable explanation for failing to meet the Replacement Deadline (b) Where a small customer switches retailers during the final Interim Period but before a Legacy Meter at the small customer's connection point is replaced, ensure the Legacy Meter is replaced by the later of: 1. the Replacement Deadline; or 2. six months after the small customer switches retailers.	Tier 1	Failure by retailers to ensure that legacy meters are replaced by the end of the acceleration period could result in customers not have access to services and offers that customers with smart meters do. Further, it would impact the success of other reforms, which rely on the deployment of smart meters, including access to power quality data to enable DNSPs to better manage their networks.

The final retail rule includes two new provisions in the NERR, which the Commission proposes to recommend to the Energy Ministers' Meeting be classified as civil penalty provisions, as set out below.

Table C.2: NERR civil penalty provision recommendations

Clause	Description of clause	Proposed classification	Reason
Schedule 3, Division 4, rule 2(2)	If a small customer's Legacy Meter is replaced with a Type 4 or Type 4A *meter* and, because of that replacement, the small customer's retailer intends to vary the tariff structure that applies to the customer during the Explicit Informed Consent Period, then the retailer must issue a notice to the	Tier 3	Failure to provide customers with sufficient supporting information prior to a retail tariff structure variation could lead to negative customer impacts, such as bill shock.

Clause	Description of clause	Proposed classification	Reason
	customer, and the notice must contain the specified information.		
Schedule 3, Division 4, rule 3	A retailer may only vary the customer's tariff structure during the Explicit Informed Consent Period if it obtains the customer's explicit informed consent following notification under subrule (2).	Tier 1	Failure to obtain a customer's explicit informed consent prior to a retail tariff structure variation could lead to negative customer outcomes and experiences, such as bill shock.

Where the final rules amend provisions in the NER or NERR that are currently classified as civil penalty provisions, the Commission does not propose to recommend to the Energy Ministers' Meeting any changes to the classification of those provisions.

Where the final rules remove provisions in the NER or NERR that are currently classified as civil penalty provisions, the Commission proposes to recommend to the Energy Ministers' Meeting that these provisions cease to be classified as civil penalty provisions.

D Summary of the final rules

This Appendix outlines the amendments to the NER and the NERR that are made by the final rules (the Electricity Amending Rule and the Retail Amending Rule).

D.1 Commencement of the final rules

The final rules have the following commencement dates:

- Electricity rule:
  - 5 December 2024:
    - Schedule 4: This transitional schedule includes the Legacy Meter Replacement Plan (LMRP) framework. It also includes other provisions to enable the AER and AEMO to amend and publish, where they consider it necessary or desirable, procedures, guidelines, and other documents to take into account the electricity rule.
  - 1 December 2025:
    - Schedule 1: This schedule includes amendments to the metering installation malfunction framework, including the shared fusing replacement procedure, and the testing and inspection framework.
    - The commencement date recognises the implementation work that stakeholders will need to complete to comply with the changes. It will also allow AEMO to implement any changes to its processes and systems in line with any amendments it has made to relevant documents.
  - 31 May 2026:
    - Schedule 3: This schedule amends the inspection timeframes for whole current meters. It will commence immediately following an amendment that will be made on 31 May 2026 under the National Electricity Amendment (Unlocking CER benefits through flexible trading) Rule 2024.
  - 1 July 2026:
    - Schedule 2: This schedule includes amendments to the rules regarding basic PQD.
    - The commencement date recognises the stakeholder implementation work required for the basic PQD changes and the benefits DNSPs, consumers and the broader energy market may obtain from basic PQD.
- Retail rule:
  - 1 June 2025:
    - Schedule 1: This schedule includes broader amendments to the NERR, including changes to customer notices, enabling small customers to request a meter for any reason and the removal of opt-out provisions.
  - 1 December 2025:
    - Schedule 2: This schedule includes amendments to the NERR to establish notice procedures for defects at the metering installation.
    - Schedule 3: This transitional schedule includes amendments to implement the tariffs and charges safeguards.

D.2 NER key concepts

The final rule includes several changes to the NER, which can be broadly grouped as follows:

1. Introducing a process for the rollout of smart meters by 2030, by providing for the development and implementation of LMRPs. DNSPs are required to develop, through consultation with affected stakeholders, including retailers, plans for the replacement of all legacy meters (excluding type 5 meters with remote acquisition capabilities). Retailers are responsible for arranging for the replacement of legacy meters in accordance with those plans. The AER has a compliance oversight role to approve the LMRPs.
2. Introducing a streamlined replacement process for meters impacted by shared fusing.
3. Improving the repair process for malfunctioning meters in clause 7.8.10 and the associated exemptions procedures. The amended process will link to the shared fusing meter replacement procedures and also improve processes and timeframes for repair.
4. Amending the requirements for meter testing and inspections under asset management strategies developed by MCs. AEMO will be required to develop Asset Management Strategy Guidelines to facilitate the development and implementation of asset management strategies.
5. Introducing a definition of 'basic power quality data' and facilitating the collection and delivery of basic PQD from smart meters, which is defined as the following characteristics of the power supply as measured by a meter: measurements of (voltage, current and phase angle, delivered as required under the procedures that AEMO will develop to support the framework for basic PQD (basic power quality data procedures). This will be made available to DNSPs to support network planning.

Changes are made to Chapter 7, Chapter 10 and Chapter 11 of the NER. These changes are discussed in more detail in D.3 below.

D.3 NER amendments by chapter

D.3.1 Chapter 7

The final rule amends and supplements existing provisions in Chapter 7 to achieve the objectives set out at paragraphs 2 to 5 above. The relevant provisions include requirements for the testing and inspection, replacement, and repair of metering installations, as well as a regime for the collection and handling of data associated with metering installations.

The key changes are detailed in the table below.

Table D.1: List of changes to Chapter 7

	Provision	Amendment
Power quality data		
1	Clause 7.3.1	Clause 7.3.1 sets out the responsibilities of an MC. It is amended to expand those responsibilities to the collection, processing and delivery (to relevant people) of basic PQD, as well as managing the security of and access to basic PQD (per cl 7.3.1(a) (3)).
2	Clause 7.3.2	Clause 7.3.2 contains a new section ('Basic power quality data') that includes the requirements relating to basic PQD. Paragraph (j) provides that an MC is responsible for the collection, processing and delivery of basic PQD. Paragraph (k) provides the obligation for MCs to provide basic PQD and NMI standing data to relevant people specified in clause 7.15.5(c2).

	Provision	Amendment
		Paragraph (l) covers the circumstances where the MC is exempted from its obligation to provide basic PQD. This includes when the meter is not capable of supporting the remote collection and communication of basic PQD or for other reasons outside the MC's control that cause a metering installation to be temporarily unable to collect or communicate basic PQD. Paragraph (m) provides that if an MC becomes aware that incorrect basic PQD is provided to a person, then it must provide the correct basic PQD to that person.
3	Clause 7.10.3	Clause 7.10.3 deals with the provision of metering data to certain people. Paragraph (b) is amended to extend restrictions on the provision of data to include basic PQD.
4	Clause 7.15.1	Clause 7.15.1 deals with the confidentiality of relevant data. This clause is extended to include reference to basic PQD by amending paragraphs (a) and (b).
5	Clause 7.15.4	Clause 7.15.4 provides for additional security controls in respect of small customer metering installations. This clause is extended (new paragraph (b1)) to provide that an MC must ensure that basic PQD is only given to a person and for a purpose that is permitted under the NER.
6	Clause 7.15.5	Clause 7.15.5 provides for access to energy data. This clause is expanded to provide Local Network Service Providers (LNSPs), MPs, MCs, MDPs, the AER and AEMO with a right to receive basic PQD in respect of a small customer metering installation (new paragraphs (c2) and (c3)). The parties able to access basic PQD under paragraph (c2) (being LNSPs, AEMO and the AER) can access it free of charge. It is also amended to ensure that basic PQD is accessed in a way that ensures congestion does not occur (cl 7.15.5(b)).
7	Clause 7.16.6C	New clause 7.16.6 provides for the development, maintenance and publication of procedures relevant to basic PQD. Paragraph (b) sets out the matters that must be included in the basic PQD procedures, including procedures for collection, processing and sharing basic PQD and appropriate service levels. Paragraph (c) sets out additional matters that may also be included in the procedures. Paragraph (d) provides that the basic PQD procedures may be published as a standalone document or may be included in other procedures published under rule 7.16.
Metering installation malfunction processes and shared fusing metering replacement procedure		
8	Clause 7.8.10	Clause 7.8.10 deals with metering installation malfunctions. The timeframes for repair of a metering installation at a small customers premises (set out in cl 7.8.10(a)(2)) are amended to have different timeframes for individually identified malfunctions and family failures (which are new definitions inserted into Chapter 10, as described below).

	Provision	Amendment
		The clause is also amended to remove the extension of time for repair where a meter has shared fusing; instead, where there is shared fusing, the Shared Fusing Meter Replacement Procedure (described below) will apply. The process for obtaining exemptions from the repair timeframes is also amended. Currently a Metering Coordinator must provide a plan for rectification of the metering installation once it has been granted an exemption. Under the final rule, the plan will need to be provided at the time of making the application.
9	Clauses 7.8.10A, 7.8.10B and 7.8.10C	Clauses 7.8.10A, 7.8.10B and 7.8.10C deal with the timeframes for the replacement of meters in certain circumstances. Paragraph (c1) of each of these clauses is amended so that rather than the current timeframes for where there is shared fusing, the Shared Fusing Meter Replacement Procedure (described below) will apply.
10	New clause 7.8.10D	A new clause 7.8.10D is inserted to introduce the Shared Fusing Meter Replacement Procedure. Under the new process, where a Metering Coordinator becomes aware that repairing, installing or replacing a metering installation requires interrupting supply to other small customers, this will trigger a process for replacement of all the affected meters. Once the Metering Coordinator becomes aware of the shared fusing, it must notify the relevant retailer. The retailer must in turn notify the LNSP, who must then identify each NMI that will require interruption of supply. The LNSP must then issue a notice to each relevant retailer specifying a date for replacement of all the Legacy Meters (unless there are no Legacy Meters on the shared fusing per paragraph (c1)). The retailers must then appoint MCs and arrange for the replacement of the meters on the designated date.
Testing and inspection		
	Clause S7.6.1	Clause S7.6.1 deals with inspection and testing requirements for metering installations. Clause S7.6.1 is amended to require AEMO to develop asset management strategy guidelines that provide guidance to MCs on the development of their asset management strategies. The amendments also provide AEMO with the matters it must take into consideration in developing or amending the asset management strategy guidelines. It is also amended to include an asset management strategy objective, which provides that the objective of an asset management strategy is to ensure MCs have a testing and inspection strategy in place to reliably test meter accuracy and detect meter condition faults in a reasonable period. Minor amendments to cl S7.6.1(c) are also made to implement the

	Provision	Amendment
		new definition of asset management strategies (which is inserted into Chapter 10, as described below).
	Clauses S7.1.2 and S7.6.2	Clauses S7.1.2(b)(6) and S7.6.2 are amended to include reference to asset management strategies (which is a new definition inserted into Chapter 10, as described below).
	Tables S7.6.1.2 and S7.6.1.3	Each of tables S7.6.1.2 and S7.6.1.3 are amended to require testing and inspections to be undertaken in accordance with an asset management strategy unless covered by a Legacy Meter Replacement Plan. They are also amended to remove the requirement that the asset management strategy guidelines must be included in the metrology procedure. The tables are amended by Schedule 1 of the Amending Rule on 1 December 2025. However, table S7.6.1.3 is amended again by Schedule 3 of the Amending Rule on 31 May 2026 in order to account for additional changes made to that table in the meantime by Schedule 2 of National Electricity Amendment (Unlocking CER benefits through flexible trading) Rule 2024 No.15.

D.3.2 Chapter 10

A number of new definitions are added to Chapter 10, and some existing definitions amended, to facilitate the above changes to Chapter 7. These are set out in the table below.

Table D.2: List of amendments to Chapter 10

	Definition	Proposed amendment
1	asset management strategy	A new definition of “asset management strategy” is included. The definition is tied to the approval of a strategy under cl S7.6.1.
2	Asset Management Strategy Guidelines	A new definition of “Asset Management Strategy Guidelines” is included. The definition is tied to the description and requirements for the Asset Management Strategy Guidelines under cl S7.6.1(g).
3	family failure	A new definition of “family failure” is included and provides that “family failure” is a type of metering installation malfunction that is identified through sample or statistical testing conducted pursuant to an asset management strategy.
4	individually identified malfunction	A new definition of “individually identified malfunction” is included and provides that an “individually identified malfunction” is a type of metering installation malfunction that that is not identified through sample or statistical testing conducted pursuant to an asset management strategy.

	Definition	Proposed amendment
5	Legacy Meter	A new definition of “legacy meter” is included and is defined as any type 5 and 6 metering installations in operation at 1 July 2025, other than type 5 metering installations capable of remote acquisition.
6	Legacy Meter Replacement Plan or LMRP	A new definition of “Legacy Meter Replacement Plan” is included and defined by reference to the transitional provisions in clause 11.177.1, which set out the process for developing, consulting on and complying with LMRPs.
7	defect at the metering installation	A new definition of “defect at the metering installation” is included and is defined as a defect with an end user’s housing of a metering installation or electrical wiring connected to the metering installation that means the metering installation is unable to be repaired or replaced.
8	NMI Standing Data	The definition of NMI Standing Data is amended to include the profile type applicable to the connection point, reference to metering installation defects and any data referred to in the Market Settlement and Transfer Solution Procedures as forming NMI Standing Data.
9	Shared Fusing Meter Replacement Procedure	This new term is added and defined by reference to the new procedure set out in clause 7.8.10D.

D.3.3 Chapter 11

Chapter 11 is amended to include a new transitional provision, rule 11.177, that introduces a process for the acceleration of the rollout of smart meters.

The final rule includes an “LMRP Objective”, which requires that all legacy meters (being type 5 and 6 metering installations in operation on 1 July 2025 other than type 5 metering installations capable of remote acquisition) be replaced with type 4 meters in a timely, cost effective, fair and safe way during the LMRP Period (1 December 2025 and 30 November 2030). The LMRP Objective will be supported by requiring the development and implementation of LMRPs.

Local Network Service Providers will be responsible for the development of the LMRPs, and retailers will be responsible for the replacement of the legacy meters covered by an LMRP. The AEMC will recommend that civil penalties apply if a retailer fails to replace all legacy meters for which it is responsible by the end of the LMRP period.

Development, consultation and approval of the LMRP

LMRPs will be developed by Local Network Service Providers and will cover the replacement of all legacy meters at connection points on the Local Network Service Provider’s distribution network. LMRPs will include a description of the replacement program, including the total number of legacy meters to be replaced in each year of the LMRP Period (described as Interim Targets), and a summary of the process for the development of the LMRP, including how the LNSP engaged with stakeholders and addressed their concerns. [264]

264 Clause 11.177.2(b) of Schedule 3 of the Amending Rule

In developing an LMRP, a LNSP will be required to have regard to the "LMRP principles", which include:

- that for each Interim Period, the target for replacement of legacy meters should be around 15-25 per cent
- the overall efficiency of the LMRP, including costs and potential cost savings for market participants.
- the impact of the LMRP on Affected Retailers (being retailers impacted by the LMRP) and other affected stakeholders
- appropriate and efficient workforce planning, including in regional areas.

By 28 February 2025, the LNSP must provide a copy of a draft LMRP to Affected Retailers and MCs, as well as a schedule specifying the legacy meters and corresponding NMIs to be replaced in each Interim Period, and must invite feedback on the draft LMRP. [265]

Following consultation, and no later than 30 June 2025, the LNSP must submit the draft LMRP to the AER for approval. The AER will be required to approve an LMRP where it meets the "LMRP Requirements", being the requirements set out in clauses 11.1772 and 11.177.3. If the AER does not approve the LMRP, then the LNSP will be required to resubmit the LMRP in a form that complies with the LMRP Requirements and addresses any defects identified by the AER.

Once the LMRP has been approved, the AER must publish a copy, and the LNSP must notify Affected Retailers and MCs, provide them with a copy of the schedule specifying the legacy meters and corresponding NMIs to be replaced in each Interim Period, and record the details of the LMRP in MSATS. [266]

Amendment of an LMRP

An LMRP may only be amended where it is affected by a "Material Change Event" or "Material Error" which, broadly, means a change in circumstances (that was not reasonably foreseeable) or an error which would materially adversely affect the Affected Retailers ability to comply with the LMRP.

The amendment process, at a high level, requires that an Affected Retailer make an amendment application to the LNSP, setting out the Material Change Event or Material Error and the reasons why a failure to amend the LMRP is likely to materially adversely affect the Affected Retailer's ability to comply with it. Following receipt of an application, the LNSP may (at its discretion), amend the LMRP and, in doing so, may either accept amendments proposed by the Affected Retailer or may propose and consult on its own amendments in accordance with the consultation procedure described above (and set out under clause 11.177.3). The amended LMRP must then be submitted to the AER for approval following the same process as outlined above.

Interim Targets

The new provision will include that, the day immediately prior to commencement of each Interim Period, the LNSP must make an Interim Target available in MSATS to each Affected Retailer. The Interim Target must identify the connection point and corresponding NMI for each legacy meter to be replaced in the Interim Period by the Affected Retailer. The Affected Retailer must use its best endeavours to meet the Interim Target.

Replacement Deadline

265 Clause 11.177.3 of Schedule 3 of the Amending Rule

266 Clause 11.177.4 of Schedule 3 of the Amending Rule.

A retailer must ensure that all legacy meters for which it is the financially responsible Market Participant on 30 November 2030 (the Replacement Deadline) are replaced by that date, unless the Affected Retailer has a reasonable explanation for failing to meet the deadline. [267] The AEMC recommends this provision be a civil penalty provision.

However, where a small customer switches retailers during the final Interim Period (i.e., between 1 December 2029 and 30 November 2030), then the incoming retailer will be given a six-month grace period in which to replace the meter.

Reporting requirements

The final rule includes reporting requirements for Affected Retailers and the AER.

Affected Retailers will be required to report to the AER on their compliance with the LMRP for each Interim Period. The report must be provided to the AER within two months of the end of each Interim Period (i.e. by 31 January the following year). At a high level, the reporting requirements include how many legacy meters the Affected Retailer replaced in the Interim Period and the percentage of the Interim Target that was achieved, details regarding the replacement of meters where the customer switched retailers, how many legacy meters the Affected Retailer will need to replace in the future Interim Periods, and an explanation of its progress against the Interim Targets.

There will be additional reporting requirements for the final Interim Period. In addition to the matters set out above, Affected Retailers will have to include in their reporting: the total number of legacy meters that the Affected Retailer replaced over the LMRP Period; whether the Affected Retailer has complied with the obligation to meet the Replacement Deadline and reasons for any non- compliance; and the Affected Retailer's plans to replace any legacy meters that had not yet been replaced.

In addition, by 31 July 2031, Affected Retailers will also need to provide a final report to the AER regarding their compliance with the LMRP. The report must include, how many legacy meters the affected retailer replaced during the LMRP period, the percentage of legacy meters that the affected retailer replaced relative to each of its interim targets, and whether the Affected Retailer replaced all legacy meters for which it was the financially responsible Market Participant by the Replacement Deadline and, if any were not replaced, the number that were not replaced and the reasons why.

Within four months of the end of each Interim Period (i.e. by 31 March the following year), the AER is required to report on Affected Retailers' compliance with the interim targets and progress against the LMRP Objective. [268]

In addition, by 31 December 2031, the AER is required to report on Affected Retailers' compliance with the replacement deadline and whether the LMRP Objective has been met. [269]

Other amendments

The final rule also includes:

- a prohibition on retailers charging upfront costs or exit fees to new small customers for the replacement of legacy meters that are replaced pursuant to an LMRP. The prohibition applies until 31 May 2031. [270]

267 Clause 11.177.7 of Schedule 3 of the Amending Rule.
268 Clause 11.177.8(d) of Schedule 3 of the Amending Rule.
269 Clause 11.177.8(e) of Schedule 3 of the Amending Rule.
270 Clause 11.177.9 of Schedule 3 of the Amending Rule.

- a deeming provision that renders certain information under the new provision to be NMI Standing Data during the LMRP period. [271]
- a provision that extends the usual timeframes for meter installation under clauses 7.8.10A, 7.8.10B and 7.18.10C of the NER by 5 business days during the LMRP period. [272]
- a requirement for AEMO to update the Market Settlement and Transfer Solution Procedures by 2 April 2025 to facilitate the collection and input of information regarding defects at metering installations and information regarding legacy meters to be replaced under an LMRP. [273]
- provision for general updates by the AER and AEMO to make any amendments to procedures, guidelines and other documents that are required to take into account the final rule. [274]

D.4 NERR key concepts

The final rule also includes changes to the NERR, which can be broadly grouped as follows:

- facilitating the acceleration of the rollout of smart meters by removing a small customer's rights to opt out of receiving a smart meter;
- expanding the circumstances in which a notice must be given regarding replacement of a meter, and amending the information required to be provided under those notices; and
- introducing notice requirements in relation to defects at metering installations and in relation to tariff changes where a meter is replaced pursuant to a LMRP.

The key NERR changes are summarised in the table below.

D.5 NERR amendments

Table D.3: Amendments to the NERR

	Provision	Amendment
1	Rules 59A and 59C	Rule 59A deals with notices to small customers on deployment of new electricity meters and includes details regarding a small customer's right to opt out of a meter replacement. The final rule amends this to remove the customer right to opt out of having their meter replaced (requiring amendments to r 59A(1), (3), (4), (5), (6), (7), (8) and (9)). To ensure appropriate notice is given for a replacement under a LMRP, r 59A(2) is amended to expand the circumstances in which a notice must be given to include where a meter is replaced with a Type 4 or 4A meter (including where the replacement does not constitute a "new meter deployment", which is the language currently used in the provision). The notice requirements under r 59A are also streamlined. The number of notices required to be issued will be reduced from two to one (requiring amendments to r 59A(2) and (3)), and the timeframe for issuance will be between 4 and 60 business days before the meter is due to be replaced (r 59(2)).

271 Clause 11.177.10 of Schedule 3 of the Amending Rule.

272 Clause 11.177.11 of Schedule 3 of the Amending Rule.

273 Clause 11.177.12 of Schedule 3 of the Amending Rule.

274 Clause 11.177.13 of Schedule 3 of the Amending Rule.

	Provision	Amendment
		If a retailer has obtained the customer's explicit informed consent to a meter replacement occurring on any day within a date range of five business days or on a specific date, then they must provide a notice on the meter upgrade within five business days of the date of the meter replacement. If explicit informed consent is not obtained, the 4-60 business day notice period applies. The information required to be provided under the notice (r 59A(3)) will also be amended to remove the current requirements regarding opt out rights and to include: • reasons why the meter is being replaced • a summary of services available as a result of having a type 4 meter • dispute resolution options and relevant contact details • the customer's rights and responsibilities regarding the new meter • how the customer can access data from the meter • any changes to the contract as a result of the meter replacement. • where the customer has given explicit informed consent, the notice requirements are varied under r 59A(4). A minor amendment to r 59C(3) is also required, to reflect the reduction from two notices to one under r 59A.
2	New rule 59AA	A new rule 59AA : • allows a small customer who has a meter other than a type 4 meter to request their meter be replaced with a type 4 meter • requires a retailer, following such a request, to replace the customer's meter with a type 4 meter in accordance with the relevant provisions of the NER.
3	New rule 59AAA	A new rule 59AAA introduces notice requirements where a defect at the metering installation (defined in Chapter 10 NER) is identified. Broadly, the provision requires that where a metering coordinator cannot install a meter because of a defect at a metering installation, it must notify the relevant retailer who must in turn notify the small customer and request the rectification of the defect. If the retailer has not received confirmation from the small customer that the defect has been rectified within 40 business days, the retailer must send the small customer another notice. 40 business days after issuing the second notice, the retailer must seek confirmation of whether the defect has been rectified and, if so, must progress the installation in accordance with the requirements of the NER. If the defect has not been rectified, or the retailer cannot confirm, then the retailer is not required to complete the installation. If the small customer at the site changes, or if the small customer

	Provision	Amendment
		changes retailers, then the process restarts.
4	Rule 91A	Rule 91A is amended to include a timeframe for an interruption if the Shared Fusing Meter Replacement Procedure under clause 7.8.10D applies.
5	Schedule 3, Division 4	Schedule 3 contains the savings and transitional rules for the NERR. These new provisions in Division 4 require retailers to provide a notice to small customers regarding any change in tariffs arising from the replacement of the customer's meter with a type or type 4A meter. This will only apply during the smart meter rollout acceleration period from 1 December 2025 to 31 May 2031). If the small customer's meter is replaced with a type 4 or type 4A meter and because of that replacement, the retailer intends to vary the tariff structure in the two-year period immediately following the meter replacement (defined as the 'Explicit Informed Consent Period') then the retailer must issue the notice to the small customer which contains all of the information in rule 2(2). During this Explicit Informed Consent Period, the retailer must obtain the small customer's explicit informed consent before it can vary the customer's tariff. After the Explicit Informed Consent Period ends, a retailer may vary the tariff structure that applies to the customer in accordance with the requirements of rule 3. Rule 4 of the Division will only apply in jurisdictions where it is declared to apply under a local instrument. Where it applies, if a small customer's Legacy Meter is replaced with a type 4 or type 4A meter, then the designated retailer must offer the customer the option of a flat tariff structure. Rule 5 sets out the scope and application of the Division.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMS	Asset management strategy
CBA	Cost-benefit analysis
CER	Consumer energy resources
Commission	See AEMC
DNSP	Distribution network service provider
EV	Electric vehicle
FRMP	Financially responsible market participant
LMRP	Legacy Meter Replacement Plan
LNSP	Local Network Service Provider
MC	Metering coordinator
MCE	Ministerial Council on Energy
MDP	Metering data provider
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
NMI	National Meter Identifier
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
Proponents	The individual / organisation who submitted the rule change request to the Commission
PQD	Power quality data
PV	Photovoltaic
Review	Review of the regulatory framework for metering services
TIGS	Temporary Isolation of Group Supply

E Summary of other issues raised in submissions

Table E.1: Summary of other issues raised in submissions on the draft determination

Shared Fusing Meter Replacement Procedure	TasNetworks, SA Power Networks, PLUS ES, Bluecurrent, Endeavour	Under the Shared Fusing Meter Replacement Procedure there should be additional obligations on parties relating to downstream industry processes or transactions. For example, an obligation on retailers to make supporting commercial arrangements with the MC for a meter replacement.	Parties' obligations under the Procedure are clear. We do not consider that it is appropriate for the national regulatory framework to prescribe additional commercial arrangements and transactions between parties.
Shared Fusing Meter Replacement Procedure	Ausgrid, Energy Queensland, Energy Locals	Depending on how retailers raise requests, there may be boom and bust cycles due to the Shared Fusing Replacement Procedure, which may cause challenges for DNSP resourcing.	DNSPs can consider known shared-fuse arrangements when developing LMRPs. We note that DNSPs should have some record of shared fusing arrangements following the *Introduction of metering coordinator planned interruption* rule change in 2019. It made a final rule for AEMO's metrology procedure to require DNSPs to record shared fusing information as soon as practicable after becoming aware of the shared fuse arrangements. To facilitate the collation of shared fusing information, retailers and metering parties are required to notify the DNSP as soon as practicable of any shared fusing they have identified. Additionally, under the final rule we have extended the timeframes for DNSPs to meet their obligations under the Procedure.
Site defect notification and tracking	PLUS ES, AGL, Origin	Once the new system to record metering installation defects becomes available in MSATS under the final determination,	We consider retrospectively recording site defect information poses a risk that the information is not up to date or correct.

process		parties should beable to record previously identified defects.	
PQD	Powermetric, Australian Privacy Foundation, PIAC	Basic PQD could be used to determine customer behaviour and for unintended purposes. The NER should recognise that all meter data generated and made available is the property of consumers and subject to their control.	Under the final rule, PQD is subject to the confidentiality framework in Chapter 8 of the NER. We are considering consumer access to smart meter data through our *Real-time data for consumers* rule change. (AEMC, *Real-time data for consumers* rule change https://www.aemc.gov.au/rulechanges/real-time-data-consumers,https://www.aemc.gov.au/rule-changes/empoweringconsumers-real-time-data).
PQD	PIAC	Metering costs should be transparent and regulated if the PQD framework distinguishes between basic and advanced PQD. This would allow additional costs for advanced PQD services to be reliably identified ensure consumers are not 'paying twice'.	We do not consider that basic or advanced PQD costs need to be regulated because: • we expect MCs to include the basic PQD costs as part oftheir offer to a retailer's competitive sourcing process,which would drive efficient cost outcomes • there is sufficient competition in the metering services market for DNSPs to procure advanced PQD for the advanced PQD use cases as set out in the Review final report (AEMC, Review final report, pp. 123-4, Table E.2.) We also note that the DNSP revenue determination framework ensures transparency over any costs DNSPs seek to recover from consumers. If DNSPs seek to recover PQD costs from consumers, they would need to justify any proposed step up in costs in their five yearly revenue proposals (NER, Chapter 6), or apply for adjustments to revenue determinations if there is a regulatory change event (NER, Rule 6.6.). However, we do not expect such revenue determination adjustments would be likely, as:

			• our final rule gives DNSPs a right to basic PQD, but does not impose an obligation on them • the net cost increase (if any) to the DNSP is unlikely to meet the materiality threshold.(NER, Chapter 10, definitions of“regulatory change event” and “materially”.)
PQD	PIAC	Civil penalties should cover contracts between retailers and metering parties which unduly limit the availability of data, restrict the use of the meter or otherwise exercise an unreasonable‘monopoly’ control over the meter.	The basic PQD arrangements provide a framework by which DNSPs can receive access to basic PQD. Similar to the access arrangements to metering data, retailers would be unable to limit DNSP access to basic PQD. The civil penalties relating to the matters proposed are beyond the scope of this rule change.
PQD	Bluecurrent	The basic PQD service should be subject to commercial arrangements between MPs and DNSPs.	Consistent with the Review recommendations, we consider that basic PQD should be provided free of charge. We do not consider that there has been new evidence or information put before the Commission since the Review final report to justify a change from this position.
PQD	Bluecurrent	Clauses 7.6.1(b) and 7.4.3(b) of the NER allow retailers to use commercial agreements to restrict MPs’ provision of advanced PQD. Through these agreements, retailers can restrict MPs from offering a similar lower cost product using advanced PQD than retailers.	The proposed change has not been included in the final rule. We consider that the issue requires greater consultation with stakeholders beyond the current rule change process.
PQD	Bluecurrent	AEMO’s implementation work should be limited to assisting to develop a technical guideline that stakeholders can use to standardise the exchange of basic PQD.	AEMO is the market body with the relevant technical expertise to lead industry implementation of the basic PQD arrangements. The final rule provides flexibility to stakeholders to work with AEMO to design and develop a basic PQD exchange mechanism. Changes to AEMO

			processes and procedures will be also necessary to support the basic PQD arrangements.
PQD	Powermetric, Bluecurrent	The recommended civil penalty is inequitable, excessive, unreasonable and disproportionate.	We recommend a Tier 2 civil penalty where MCs do not comply with the requirement to collect, process and deliver basic PQD for the reasons outlined in Chapter 3.2.5.
PQD	SA Power Networks, Jemena	Basic PQD should be provided to DNSPs for a broader range of customers and meter types than identified in the draft rule.	The final rule applies only to small customer meters with remote communications enabled, such as Type 4 meters, which is consistent with the recommendations in the Review final report. It is beyond the scope of this rule change to expand the basic PQD service to Type 1 to 3 or large customer meters.
PQD	Evoenergy	There should be cost recovery for an advanced PQD service, but the AEMC and AER need to consider how the advanced PQD service is monitored.	Consistent with our findings in the Review Final Report, parties should be able to negotiate the terms, conditions and prices of advanced PQD services on a commercial basis (AEMC, Review final report, p. 122.) The implementation of this position does not require changes to the NER. The NER's existing enforcement framework also applies to any advanced PQD service.
PQD	ENGIE	There should be some oversight of DNSPs' usage of basic PQD to ensure there is value for industry providing DNSPs with basic PQD access free of direct charge.	Stakeholders will be able to raise any concerns on the ongoing value of the basic PQD arrangements during relevant metering framework reviews and rule changes.
PQD	AusNet	The final rule should delay a requirement on MCs to deliver basic PQD from existing large customer meters to July 2026	The final rule only requires MCs to provide basic PQD from small customer meters. There is no requirement for MCs to provide basic PQD from large customer meters.
PQD	Jemena	The final rule should not require basic PQD to be delivered from Type 5, Type 6 and to Victorian small customer meters, but from	The final rule requires MCs to give basic PQD from small customer meters capable of remote collection and communication. These small customer meters are also

		Type 4 meters.	required to meet the minimum services specification in Schedule 7.5 ofthe NER. This obligation therefore does not apply to Type 5 and 6 meters, and Victorian small customer meters which meet theVictorian Specifications.
PQD	Ausgrid	If metering providers are unable to meet the basic PQD arrangements' commencement date of 1 July 2025, customers should not continue to pay for existing services procured by DNSPs that largely fit the AEMC's proposed definitions and requirements for basic PQD.	The basic PQD arrangements will enable a standardised service that will commence on 1 July 2026. AEMO procedures will contain further detail on basic PQD and the basic PQD service,which will be finalised by 30 September 2025. Given the complexity of implementing the basic PQD arrangements, the proposed change would cause additional complexity and require stakeholders to determine which existing services fall within the basic PQD arrangements before this further detail has been finalised in AEMO procedures. Requiring stakeholders to determine which existing services fall within the intended basic PQD arrangements would also distract stakeholder resources from the proper implementation of the basic PQD service by 1 July 2026 and other aspects of the final rule, such as the accelerated smart meter deployment. We note that metering parties could already provide basic PQD at zero cost before the commencement of the basic PQD arrangements if they agree with DNSPs to do so.
PQD	Endeavour Energy	If AEMO's exchange platform is not sufficiently developed to facilitate basic PQD exchange by the commencement of the basic PQD arrangements, the final rule should provide flexibility to DNSPs and metering parties to utilise existing peer-to-peer mechanisms to exchange basic PQD	The final rule provides flexibility to stakeholders to work with AEMO to design and develop a basic PQD exchange mechanism. Given the basic PQD arrangements will commence on 1 July 2026, we expect stakeholders to design, build and test systems for the successful exchange of basic PQD by the commencement date.

		consistent with the Review's recommendations.	
Testing and inspection	Bluecurrent, Master Electricians Australia	Stakeholders proposed different default maximum testing and inspection timeframes: • Bluecurrent proposed a default maximum 15year timeframe for testing and "when meter is tested" for inspection. • Master Electricians Australia proposed a default five-year timeframe for the testing of smart meters.	We consider that a maximum default inspection timeframe for whole current small customer meters in the NER is not appropriate, (AEMC, Review final report, p. 159.) and that the expression "when meter is tested" is unclear (AEMC, Review final report, p. 157.) We recently made the *Unlocking CER benefits through flexible trading* final rule to clarify the maximum default inspection timeframes for metering installation equipment (see changes to Table S7.6.1.3 in clause S7.6.1 of the NER (*Unlocking CER benefits through flexible trading) Rule 2024 No. 15*). We also consider that a default five-year timeframe for the testing of smart meters is not required. The testing of whole current smart meters in line with an AMS is appropriate because it affords flexibility to smart meter testing measures, which a default five-year testing timeframe does not. For example, an AMS can be used to enable sample-based testing for smart meters.
Testing and inspection	Master Electricians Australia	Licenced electrical contractors should be automatically recognised as accredited service providers to efficiently and accurately test and identify faults in Type 4 meters.	AEMO's procedures allow accredited MPs to use subcontractors to conduct work on their behalf, (AEMO, Metering Service Provider Service Level Procedures, section 2.2.) which can include licenced electrical contractors. Further, changes would require additional stakeholder consultation, which is beyond the scope of the current rule change process.
Testing and inspection	PLUS ES	The maximum default inspection timeframe should be changed for Type 3	We recently made a decision regarding the maximum default inspection timeframes for Type 3 meters under the

		meter ≥2GWh PA to 2.5 years, and <2GWh PA to as per AMS. It is an anomaly to inspect a Type 2 meter with check metering installed with less frequency than a Type3 meter.	*Unlocking CER benefits through flexible trading* final rule (see changes to Table S7.6.1.3 in clause S7.6.1 of the NER (*Unlocking CER benefits through flexible trading) Rule 2024 No. 15*).
Testing and inspection	PLUS ES	The AMS guidelines should be subject to the NER minor consultation procedure. Without this requirement, AEMO could potentially create an unforeseen impact. The NER minor consultation procedure would validate assumptions AEMO makes for the minor or administrative amendments.	The AMS guidelines will clarify the AMS approval process for MC meter testing and inspection strategies. They will not create new requirements or change the interpretation of the testing and inspection requirements in Schedule 7.6 of the NER.
Testing and inspection	New South Wales, South Australia and Queensland Energy and Water Ombudsmen	Exempting MCs from the requirement to test and inspect legacy meters during the LMRP period may interfere with Energy and Water Ombudsman schemes to investigate and resolve complaints.There should be a list of circumstances where MCs would be required to conduct testing and inspection of legacy meters, including under these schemes	The exemption only applies to MCs' routine and preventative testing and inspection of legacy meters in line with the testing and inspection framework in Schedule 7.6 of the NER. It does not apply to any legacy meter testing and inspection required for complaints made under Energy and Water Ombudsman schemes.
Acceleration and the LMRP	Essential Energy, Endeavour Energy, PIAC, Energy Locals	The rule change should include a process to Review the accelerated smart meter rollout (for example, a mid-term review or an annual review process).	We consider the administrative costs of these proposals are unlikely to outweigh the benefits. We note that the AER is required to closely monitor implementation of the LMRPs under its performance reporting role.
Acceleration and the LMRP	AGL, Energy Locals	A dispute resolution process may be required for the LMRP development	When developing LMRPs, DNSPs will be required to consult with impacted stakeholders including retailers. As part of

		process, particularly noting that they will be designed by DNSPs which are not accountable for delivering the accelerated rollout.	the LMRP approval process, DNSPs will be required to demonstrate to the AER how they have engaged with stakeholders and responded to any feedback or concerns. We therefore do not consider that a dispute resolution framework is required.
Acceleration and the LMRP	AGL, Energy Locals, PIAC	The threshold criteria for the LMRP revisions process may be interpreted too narrowly by DNSPs.	We have taken this risk into account. If a DNSP does not agree to amend an LMRP, retailers have an opportunity to provide this context to the AER as part of their performance reporting.
Acceleration and the LMRP	Ausgrid, Endeavour Energy, Essential Energy, Evoenergy, Intellihub, Plus ES	There should be further consideration of the transition following the acceleration process, including consideration of transferring legacy meters to retailers post-2030.	We consider the metering framework should revert to the current approach from 1 January 2031. Remaining meter replacements will progressively occur over time as the meters age and customers see value in the benefits. The AER will be reporting on the progress of the acceleration program over 2025–2030, which may inform an industry impact assessment.
Safeguards	NSA, EnergyLocals, Compliance Quarter, ENGIE, GloBird Energy, Momentum, ShellEnergy, Next Business Energy, Red Energy, AGL, Origin Energy	Changes should instead be made at the network tariff level, rather than the retail tariff level. Options could include: • requiring networks to offer a flat network tariff for customers who want them • a moratorium on network tariff changes following a smart meter deployment • a moratorium on network tariff changes more generally, or until The pricing review is completed •	We do not consider that changes to existing TSS arrangements (including temporary moratoriums on tariff reassignment) are appropriate as part of this rule change process. Changes to tariff reassignment policies are the responsibility of the AER. Nevertheless, such changes would also require further extensive consultation and work, which would risk timely delivery of the accelerated rollout. Network tariff arrangements will be considered holistically through The pricing review.

		• requiring any EIC safeguard at the retail tariff level, to be matched at the network tariff level	
Safeguards	EnergyLocals, AGL	There should be consideration of how any changes to retail tariff arrangements will be factored into the DMO, noting that the 24-25 DMO has already been set.	The AER is responsible for setting the DMO. In setting the DMO the AER must have regard to retailers' costs incurred serving customers, including the cost of managing smart meters and regulatory compliance. The 2025-26 DMO is the first expected DMO setting following the finalisation of this rule change. Retailers may provide data and other supporting evidence to the AER through the DMO-setting process.
Safeguards	ECA	As part of the proposed three-year explicit informed consent period, the AEMC should deliver a rapid review demonstrating why the explicit informed consent period should end. This review should be delivered prior to automatically reverted to mandatory tariff reassignment.	The pricing review will consider a range of matters, including future network and retail pricing arrangements. The AEMC will deliver the review final report and recommendations by March 2026. We therefore do not consider an additional review is required.
Safeguards	Joint EWOs, JEC, NSA	The proposed customer safeguards should be expanded to apply to all customers, rather than just customers that receive a smart meter during the accelerated smart meter rollout. Safeguards should also be enduring.	Under our rule-making process, we must consider the matters and issues raised in the rule change request. In this instance, the rule change request relates to the accelerated smart meter rollout, and time-limited tariff variations resulting from a meter upgrade. Therefore, our safeguards relate to these matters. We note that jurisdictions would be responsible for determining the duration of the mandatory flat tariff safeguard. We also consider that a two-year explicit informed consent period is sufficient to allow consumers to accumulate seasonal data and make an informed decision about their retail tariff. Further

			information regarding this is on page 30 of the final determination.
Safeguards	Joint EWOs, JEC, Joint COSSs	There should be more clarity on how the proposed 'mandatory flat tariff' safeguards would work, such as how long it would apply for, and when it would commence. The drafting of the mandatory flat tariff safeguard should be refined to clarify that the safeguard would apply to all customers with a smart meter, not just customers whose legacy meter is replaced with a smart meter from the time at which the rules apply.	This safeguard must be implemented by jurisdictions. Therefore, it is for jurisdictions to consider if and when this rule would come into effect, and the period for which it would apply. This rule would apply to customers who receive a smart meter upgrade, which is consistent with the matters considered in the rule change request.
Safeguards	Alinta, 1st Energy, EnergyAustralia, AEC, AGL	The proposed safeguards are inconsistent with the pricing principles under the NER, which require tariffs to become more cost-reflective. The safeguards will effectively cross-subsidise different customers.	The pricing principles relate to network cost recovery. The safeguards introduced by this rule change relate to retail tariffs and do not impact existing network pricing arrangements. The pricing review is concurrently considering network tariff arrangements and the interface between networks and retailers.
Safeguards	CEC	The AEMC should engage further with retailers offering innovative CER and VPP options, to ensure the requirements will not impact their ability to develop new retail offers.	We have consulted extensively throughout this rule change process, including through seeking submissions and running public forums. We also do not consider that our additional safeguards will prevent retailers from offering innovative products to customers.Retailers can engage with the customer to demonstrate the benefits of different tariffs, including access to new and innovative product offerings.
Safeguards	GloBird, AEC, Next Business Energy	Demand tariffs are confusing for consumers, and DNSPs should be banned	Under the Tariff Structure Statement (TSS) process, the DNSP must undertake consultation to develop tariffs that

		from mandating the assignment of demand network tariffs to residential customers.	meet the relevant requirements. The AER is then responsible for assessing the approving these tariff structures.
Safeguards	Next Business Energy	Safeguards should only be applied to residential premises, as business customers are more able to manage their usage and equipment and make commercial decisions.	We consider it is appropriate for these protections to apply to all small customers, including businesses. Small customers that are businesses may face the same risks that residential customers do from retail tariff variations, such as bill shock.
Safeguards	Next Business Energy	The AEMC should fund the development of the supporting information retailers must provide customers about monitoring and managing their energy usage. Or, the AEMC could require DNSPs to fund and provide this information.	The retailer is responsible for engaging with and managing the relationship with its customer, and therefore is the party best placed to provide their customer with useful supporting information about managing and monitoring electricity usage. We do not consider that the AEMC, as the rule maker for electricity and gas markets, is the appropriate party to fund such information.
Safeguards	AGL	The proposed safeguards may impact the commerciality and development of potential innovative products.	The new safeguards do not prevent customers from moving to different kinds of retail products and tariffs. Retailers can engage with the customer to demonstrate the benefits of different tariffs, including access to new and innovative product offerings.
Safeguards	AGL	There should be clarity regarding the appropriate treatment where products have specific associated terms and conditions requiring specific retail tariffs, or the retail tariff being aligned to the network tariff.	A retailer is required to comply with its EIC obligations set out in the Law and Rules regarding retail tariff variations following a smart meter upgrade, even where the customer's existing offer imposes other conditions.
N/A	EMR Australia, Stop Smart Meters Australia, Private individuals	Electromagnetic radiation from smart meters will have adverse health impacts. Stakeholders consider that consumers who are sensitive to electromagnetic radiation	Australian Radiation Protection and Nuclear Safety Agency (ARPANSA), the Australian Government's primary authority on radiation protection and nuclear safety, advises that there is no established scientific evidence that the low level

		be allowed to opt out of the smart meter rollout or that the rollout be paused until the health impacts of smart meters are further investigated.	radio frequency (RF) electromagnetic energy (EME) exposure from smart meters causes any health effects. More information can be found here: • https://www.arpansa.gov.au/understanding-radiation/radiation-sources/more-radiation-sources/smart-meters • https://www.arpansa.gov.au/sites/default/files/legacy/•pubs/aboutus/collaboration/js_smartmeters.pdf.
N/A	Essential Energy, Endeavour Energy	The AEMC should consider how legacy meters will be tested, maintained and read post 2030 noting the cost to DNSPs. Retailers should be responsible for all remaining legacy meters,similar to Type 1 to 4 meters.	We consider that the AMS is the appropriate mechanism to design and implement the appropriate approach to test and inspect legacy meters after the LMRP period ends in 2030. Any changes to the provisions regulating legacy meter readings and the responsibility for appointing MCs for legacy meters requires greater stakeholder consultation and is beyond the scope of this fast-track rule change.
N/A	EnergyAustralia and Alinta	There should be a metering communications campaign to be delivered by a trusted source, outlining why the rollout is occurring and how customers can benefit and be supported through the change.	The Review recommended a broad communication strategy for the accelerated deployment of smart meters. The AEMC is acting on this recommendation in partnership with Energy Consumers Australia (ECA). As part of this initiative, we have convened two steering committees, one with jurisdictions and another with industry representatives, to develop a narrative,consistent messaging, and shared communication materials for the accelerated rollout.
N/A	CCIA NSW	This rule change should not apply to embedded networks given several limitations and challenges such as diverse network structures and physical constraints.	Embedded networks are not included in this rule change to accelerate the rollout of smart meters.

N/A	EWO, Momentum Energy, Powermetric, ECA, Ausgrid, AEC, SNAPI	Governments should provide assistance to customers, particularly vulnerable consumers, who need to carry out site remediation works before installing a smart meter.	The AEMC stands by its recommendation in the Review that governments should consider funding support for vulnerable customers that need to remediate their sites. We will continue to engage with jurisdictions on this.
N/A	Jemena, ENA, Ausnet	The AEMC should consider whether the rule may have adverse impacts on customers in jurisdictions where the rollout of smart meters is almost completed or on track to be completed. For example, Jemena considers that the draft rule is inconsistent with obligations placed on Victorian DNSP's under the Victorian Government's Minimum AMI Functionality Specification and would require DNSPs to prematurely replace Type 5 meters.	We have made minor amendments to clarify that Type 5 meters capable of remote acquisition may be considered as Type 4 & 4A meters for the purpose of this rule change and do not need to be replaced as part of the accelerated rollout.
N/A	Powermetric, SNAPI	A skills shortage will likely impede the smart meter rollout. The AEMC should encourage the government to facilitate the development of skills required for the rollout.	The Review found that the 2030 target is feasible. The target date was extensively consulted on throughout the Review process with metering parties through forums, bilateral meetings, and the submissions process.
N/A	SMA, Sonnen, Nexa Advisory, CEC, Rheem and Combined Energy Technologies	Reforms should be progressed to enable consumers and authorised third parties, including aggregators, to access real time data.	We will consider these matters through our current *Real-time data for consumers rule* change process (AEMC, *Real-time datafor consumers* rule change https://www.aemc.gov.au/rulechanges/real-time-data-consumers.)
N/A	PIAC, Ausgrid, SACOSS	The existing market structure should be reviewed and DNSPs should play a greater	As articulated in the Review, the Commission has considered these matters and considers that the existing

		role in delivering LMRPs. DNSPs should have the responsibility to appoint the MCs.	industry structure is appropriate.
N/A	PIAC, Rheem and Combined Energy Technologies	The draft rule should ensure effective competition in the market for CER services, and ensure that metering parties do not exert effective monopoly power during the course of the rollout.	We consider these matters require greater consultation with stakeholders beyond the current rule change process and are more appropriate for consideration through our *Real-time data for consumers* rule change (Ibid).
N/A	Bluecurrent, PLUS ES, EnergyQueensland	Metering parties not appointed to a metering installation should have access to NMI Discovery to support metering parties' activities and functions, including to solve issues such as cross metering.	We do not support expanding access to NMI Discovery, as outlined in section 3.5.4 of the final determination.