Endeavour Energy
Revised Regulatory Proposal 2024-2029

November 2023

Endeavour Energy

POWER together

Endeavour Energy acknowledges the Traditional Custodians of the lands on which we work — the people of the Dharawal, Dharug, Gundungarra, Wiradjuri and Yuin nations — and recognises their continuing connection to Country, cultures and community. We pay our respect to elders past, present and emerging.

Featured artwork: 'Powering A Brighter Future Together' by Rhonda Sampson

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CEO Foreword

Earlier this year, we submitted our plans to the Australian Energy Regulator (AER) for the 2024-29 period. Our Proposal is vital to the affordability, security, and long-term interests of our customers. The revenue that is finally determined will be used to build and maintain an electricity network that powers the lives of over 2.7 million people, which will grow to 3 million people by 2029. It will be used to support economic growth, create jobs, keep communities safe, resilient, sustainable, and productive, and will enable customers' energy choices and lifestyles beyond the five-year period.

As our costs make up about 25% of the average residential or small business electricity bill, it's vitally important that every dollar we spend aligns with our customers' priorities. These plans are also a part of the larger and unprecedented transformation that is occurring in Australia's energy sector. The shift from fossil fuels to renewable generation, from large scale to customers' rooftop solar panels, home batteries and electric vehicles is offering opportunities for customers to participate more actively, save money and power their lives in new and innovative ways.

This transition is taking place during a time of increasing geo-political unrest, economic uncertainty and cost of living and cost of doing business pressures, as more extreme climate events impact our communities including another hot and dry El Nino summer just ahead, and as Western Sydney and our regions transform into hubs of industry, innovation and 'liveable' urban development.

To support these momentous changes and the long-term interests of customers, we have undertaken our most extensive customer engagement and research process ever to inform this Proposal. This engagement, co-designed with our key customer stakeholder representatives, has consistently confirmed that customers have increasing and evolving expectations of their energy supply and its security and sustainability. They want to be confident about the energy system's performance during this period of transformation. Customers have also urged us to support them through the recent volatility in electricity markets and broader cost-of-living and cost-of-doing-business pressures by delivering an affordable energy transition. In keeping with our responsibility to our customers, we faithfully heeded these priorities in our Proposal.

The AER recognised our extensive engagement and efforts in meeting these priorities in largely accepting our Proposal in its draft decision released in September. This is a significant positive step for our current and future customers that will enable us to support growth across Western Sydney and other regions of our network, transition to a NetZero economy, adapt to a changing climate and maintain the high-quality level of our services while actively driving efficiency and innovation in how we operate every day.

This milestone has been possible due to the collaborative and respectful relationship developed between the AER, Endeavour Energy and its many customers and stakeholders. Constructive discussion between all parties has been a key factor in shaping our expenditure forecasts and organisational focus, and we thank all of those who have participated for your valued assistance, support and feedback in helping us prepare this final five-year revenue proposal.

This Revised Proposal largely accepts the AER's draft decision and updates it for the latest available information. This translates to our distribution bills increasing by $23 per annum for the average residential customer and $41 per annum for the average small-medium business customer compared to as it is today in nominal terms. This represents a small reduction compared to our January 2023 Proposal and the AER's draft decision ($24 and $43 respectively).

In publishing this Revised Proposal, we are now seeking further input from our customers and stakeholders before our plans are finalised by the AER in April 2024. We set out a snapshot of our Revised Proposal below, which we explain in more detail in the remainder of this document.

I encourage you to find out more about what's planned and what this means for your future electricity bills on the pages that follow. We invite you to continue to have your say on how you want us to meet your electricity needs, now and in the future.

Guy Chalkley

A snapshot of our Revised Proposal

We largely accept the AER's draft decision and have only updated it to the extent necessary to reflect the latest available information. We set out the details of our Revised Proposal in the table below.

Standard Control Services ($M, Real 2023-24)	AER Draft Decision (September 2023)	Revised Proposal	Commentary
Operating expenditure (including debt raising costs)	1,497.6	1,496.6	Accept AER methodology and have updated for latest available information[1]
Net capital expenditure	1,850.9	1,850.9	Accept AER decision
Regulatory Asset Base (end period)	7,930.5	7,916.1	Updated AER decision for latest available information
Revenue Requirements			
Return on capital (WACC %)	2,361.0 (6.00%)	2,366.1 (6.00%)	Accept AER placeholder estimate
Regulatory depreciation	1,043.3	1,100.3	Updated AER decision for latest available information
Revenue adjustments	143.6	128.3	Updated AER decision for latest available information
Corporate tax allowance (Gamma 0.595)	94.2	98.9	Updated AER decision for latest available information
Annual revenue requirement (unsmoothed)	5,139.7	5,190.2	Updated AER decision for latest available information
Revenue x-factors (%)	We have proposed a similar profile for our Revised Proposal to the AER's draft decision.		
Annual revenue requirement (smoothed)	5,148.6	5,201.8	
Annual revenue requirement (smoothed) Type 5 & 6 Metering services[2]	92.6	86.5	
Energy consumption (GWh)	We accept the AER's draft decision to accept our proposed forecasts for energy consumption, customer numbers and maximum demand.		
Customer numbers			
Maximum Demand (MW)			

[1] For several aspects of the AER's draft decision we accept the methodology noting that updates are required to reflect the latest available information like FY23 actual performance and prevailing market conditions.

[2] In this revised proposal we propose Type 5 & 6 Metering Services are classified as a standard control service (SCS). The SCS revenue requirement for metering has been separately modelled. We note that for constituent decision purposes the AER will approve or substitute a total SCS revenue requirement. However, for comparison purposes with the AER's draft decision only, wherein Type 5 & 6 metering remains an alternate control service, we have listed our metering revenue requirement separately from the standard control service revenue requirements.

Key Decisions	Commentary
Service Classification	Following the AEMC's final metering review report, which constitutes a material change in circumstances, we propose amendments to the AER's draft decision with respect to the classification of Type 5 & 6 metering services and set out additional changes that may be required in support of the energy transition. We accept the AER's draft decision to continue to regulate our Dual Function Assets as distribution assets for pricing purposes.
Control Mechanisms	We accept the AER's decision to apply a revenue cap to standard control services and price cap to alternative control services. We accept the formulae to give effect to these control mechanisms as per the AER's draft decision.
Incentive Schemes	We accept the AER's draft decision to apply the following incentive schemes: • the Efficiency Benefit Sharing Scheme (EBSS); • the Capital Efficiency Sharing Scheme (CESS); • the Demand Management Incentive Scheme (DMIS) including the Demand Management Innovation Allowance (DMIAM); and • the Service Target Performance Incentive Scheme (STPIS). We accept the AER's draft decision to accept our proposed alternative approach to calculate the STPIS Major Event Day thresholds. We have updated the AER's draft decision STPIS targets for FY23 actual performance. We also accept the AER's draft decision to accept our proposed Customer Service Incentive Scheme (CSIS) in place of the customer service component of the STPIS. We have updated the AER's draft decision CSIS targets for FY23 actual performance.
Innovation Fund	We accept the AER's decision to not expressly approve an Innovation Fund. Given the rapid pace of technological change and strong customer and stakeholder support for the Innovation Fund, we remain committed to implementing a consultative committee to investigate and trial innovative technologies and solutions within the 2024-29 expenditure allowances via offsetting efficiencies.
Pass-throughs	We accept the nominated events and definitions from the AER's draft decision.
Contingent Projects	We confirm that we have no eligible contingent projects for the 2024-29 period.
Tariffs	The AER's draft decision accepted the majority of our draft Tariff Structure Statement (TSS), while requesting we consider providing additional supporting information and worked examples in support of our proposed cost reflective pricing transition period and our export charge and reward tariff. We accept the AER's draft decision and have provided the supporting information and worked examples requested by the AER. The AER did not approve our embedded network tariff and requested further supporting analysis. We have revised the proposed embedded network tariff to recognise the potential for network cost savings from the connection of embedded networks. Refer to Attachment 0.06 for further detail.
Alternative Control Services	
Public Lighting	We accept the AER's draft decision and have updated it for the latest AER benchmark labour rates.
Type 5 & 6 Metering	We propose to revise the AER's draft decision to re-classify Type 5 & 6 Metering Services from an alternate control service (ACS) to a standard control service (SCS). As an ACS, metering prices for residential customers increased from $32.67 in 2024-25 to $48.60 by 2028-29 in our January 2023 Proposal. As an SCS, metering costs are recovered from all customers resulting in a price impact reducing from $13.00 in 2024-25 to $10.40 by 2028-29 in this Revised Proposal.
Ancillary Network Services	We accept the AER's draft decision methodology. We have updated our proposal for the latest benchmark labour rates. We have also updated our security lighting service (known as 'Nightwatch') prices for the latest energy rates provided by our local retailer.

1. Purpose of this document

1.1. Purpose of this document

This document is Endeavour Energy's Revised Proposal submitted to the AER under Rule 6.10.3 of the National Electricity Rules (the Rules) on 30 November 2023.

This Revised Proposal details our proposed revisions to our operating and investment plans for the period from 1 July 2024 to 30 June 2029, responding to the AER's draft decision of 28 September 2023 and having regard to ongoing engagement with our customers and stakeholders.

The forecasts and projections included in this Revised Proposal are based on information available at this time. Although reasonable endeavours have been made to ensure accuracy at the time of writing, we note that methodologies, legislation, judicial decisions, regulatory guidance and prevailing market conditions are subject to change.

To enable comparisons of trends and costs over time, forecast and historical expenditure is expressed in real terms (excluding inflation) in 2023-24 dollars unless otherwise indicated.

The balance of this document is structured as follows.

Chapter 1 (this chapter) sets out the purpose and structure of this Revised Proposal.

Chapter 2 provides the context of the broader operating environment, including key changes since the lodgement of our January 2023 Proposal.

Chapter 3 summarises how we have engaged with our customers and incorporated their views into this Revised Proposal.

Chapter 4 sets out the detail of our Revised Proposal in response to the AER's draft decision for our service classification, incentive schemes, pass-throughs, the re-classification of Type 5 & 6 Metering Services and each of the revenue building blocks. It also sets out our proposed Type 5 & 6 Metering Services Revenue Requirement as a Standard Control Service (SCS) and the detail of our Revised Proposal for our Alternative Control Services (ACS), Public Lighting and Ancillary Network Services (ANS).

2. Our Operating Environment

2.1. Overview

Never before has the community been so focused on the affordability, resilience, reliability, sustainability and security of their electricity service, as the energy industry in Australia undergoes a dramatic transformation. We're committed to efficient investment and giving customers more choice and control.

In our January 2023 Proposal we set out the evolving challenges to providing a safe, reliable and affordable electricity service, as the National Electricity Market (NEM) is impacted by decarbonisation, decentralised generation and changing energy consumption patterns. We identified seven key trends shaping our current and future operational landscape. These are:

Customer centrality: A focus on customers' needs and experiences from high energy users to pensioners to empowered prosumers means customers play a more central role in the operation of the network as networks evolve to be platforms of energy services. Underpinned by new technologies, customer expectations and service needs will evolve. Customers will expect to help shape the direction of the business through deep engagement on regulatory proposals and beyond.

Trust, reputation and purpose: The reliable delivery of an affordable crucial service is underpinned by trust and this is core to our purpose. Customers also increasingly expect organisations to align with personal and community values for environmental, social and governance outcomes. Purposeful decision making, with an emphasis on these outcomes, will be essential to retain social licence, attract investment, and to establish and maintain a high-performance culture.

Western Sydney regional growth: The NSW Government is driving the substantial and rapid growth of Western Sydney, at a rate nearly 40% higher than the rest of Metropolitan Sydney. By 2036, half of Sydney's population will reside within the city's west, supporting a new international airport, new industry and manufacturing, and a new science park. This plan is akin to building a new city, from scratch.

Economic volatility and cost of living pressures: International and domestic developments have contributed to rapidly rising inflationary pressures, including in energy prices, with rising concerns about a possible slowdown in the Australian economy. Cost of living pressures are increasingly centre of mind now for all customers small and large. Transitioning the grid to ensure long term value for money services as customers make energy choices in the most efficient way requires balancing in the short and long-term.

Climate change and extreme weather events: Climate modelling suggests that extreme weather events will continue to increase in both frequency and intensity over the coming decades. Climate change-related events damage, destroy and/or compromise the performance of infrastructure, and increase risks to the reliable supply of electricity.

A changing grid in a low carbon economy: The pursuit of a net zero economy will transform the way we generate and consume energy. As customers take up technologies such as solar, batteries and electric vehicles, the network will need to evolve to allow for two-way flows and active participation from customers and third parties. Over time, more sophisticated digital platforms will seek to interact with a more dynamic, integrated network that facilitates the low carbon energy system.

Efficient and effective service in the digital age: Introduction of digital technologies and enhanced data capabilities create significant operational efficiencies, while transforming the risk, roles, required skills and location of the future workforce. At the same time, cyber-attacks will become more frequent and sophisticated, targeted at the disruption of energy supply.

With these external factors and based on our deep engagement with customers discussed further in Chapter 3, we co-designed our priority investment themes in the long term interests of our customers, as shown in the figure below.

Figure 2.1 Customer priority investment themes

Since our January 2023 Proposal, the cost-of-living crisis has continued to evolve along with several policy developments, including a change in State Government and amendment to the National Electricity Objective (NEO) to expressly recognise the emissions reduction objective alongside the other existing objectives. These developments confirm the continued validity and importance of the trends and investment themes outlined in our January 2023 Proposal. Below we provide more detail on key developments that reinforce the trends and themes that our Revised Proposal seeks to address.

2.2. Economic volatility and cost of living pressures

International and domestic developments have contributed to rapidly rising inflationary pressures, central bank decisions to respond with interest rate rises, and increased concern about a possible slowdown in the Australian economy are impacting our operating environment. Events in Ukraine and local factors in the NEM have contributed to supply chain challenges, wages pressure and significant rises in energy prices for Endeavour Energy customers. Cost of living pressures are increasingly centre-of-mind now for all customers small and large.

Achieving an efficient balance between cost and service quality requires risk to be managed by the party best equipped to do so. For Endeavour Energy, that means improving our service quality, especially in targeted areas most valued by customers, within a constrained budget through innovation ('finding a better way') and productivity improvements ('doing more with less'). Achieving this balance is also central to developing a proposal that represents value for money for customers and promotes their long-term interests.

Since lodging our January 2023 Proposal, achieving this efficient balance has become even more challenging. We are experiencing significant cost increases as a result of the inflationary environment as highlighted by our higher than forecast FY23 actual capital expenditure driven by rising labour and material costs. We also recognise that, over the course of our engagement activities, customers became increasingly sensitive to cost-of-living pressures. Stakeholders expressed particular concern about increases in energy costs that are outside Endeavour Energy's control, including the Rate of Return, wholesale market volatility and the NSW Renewable Energy Zone (REZ) costs.

Ordinarily, we would adjust our forecast expenditure to account for the latest available information and unit costs. However, we have only done so in this Revised Proposal where this results in a forecast that is equal to or lower than the AER's draft decision (e.g., our opex forecast). We have also updated our Proposal for the latest available information where required to do so by the Rules. For instance, our incentive scheme performance and Regulatory Asset Base (RAB) must reflect actual performance.

In addition, we have not made changes of a discretionary nature that would put further upward pressure on electricity bills when affordability remains a central concern of customers. We remain committed to providing a value for money service to our customers, as demonstrated by the constrained capex and opex forecasts contained in our January 2023 Proposal.

The largest driver of our revenue requirement is the cost of previous investments. This includes depreciation of our existing assets and a financial return on these investments. The Rate of Return (ROR), set as a Weighted Average Cost of Capital (WACC), is determined by the AER's binding Rate of Return Instrument (RORI), acknowledging that small changes in the WACC can have a material impact on our revenue requirement.

Rising interest rates, due to market conditions, are significantly increasing the cost of debt and the return required by equity investors. For instance, the yield on 10-year Commonwealth Government Securities (CGS) was 1.40% at the start of 2022 – around the time we started preparing our Preliminary Proposal. As of end October 2023, the 10-year CGS yields had increased to 4.93%.

These market conditions result in a higher WACC which in turn increases our revenue requirement. This is important context for assessing the feedback we received from customers and stakeholders and whether to update our Proposal for other recent developments.

These considerations have been front of mind in our commitment to a Proposal that constrains our expenditure forecasts and promotes prudency and efficiency. The market conditions that have resulted in increases in the WACC are central to this ongoing commitment and our decision not to incorporate increased unit cost pressures in this Revised Proposal.

2.3. Policy developments

Governments, businesses and communities are setting increasingly ambitious emissions reduction targets to limit the impacts of climate change.

This requires fundamental changes to the way we produce and consume energy and changes the nature of the energy system. Our electricity network will underpin this evolution, and we must keep pace with the change.

Since the lodgement of our January 2023 Proposal, there have been several notable policy developments at the State and Federal level that will shape our operating environment over the 2024-29 period. These developments are summarised below, with potential implications for our role in providing electricity distribution services discussed further in Chapter 4.

Amendment to the NEO

The Emissions Reduction Objectives Bill 2023 was tabled in the South Australian parliament on 14 June 2023 and subsequently passed and assent gazetted. This Act amends the NEO to include the achievement of targets set by a participating jurisdiction for reducing Australia's greenhouse gas emissions (or that are likely to).

This is a significant change to the regulatory framework that codifies the need for regulated businesses, policymakers and regulatory bodies to formally consider emissions reductions in carrying out our respective activities. The AEMC are currently in the process of assessing two rule change requests to harmonise the electricity and gas rules with the emissions objective. This includes publication of the initial target statement that sets out the emissions targets of participating jurisdictions that all entities that apply the energy objectives must, at a minimum, consider when having regard to the emissions component of the energy objectives.

Similarly, the AER are in the process of updating several instruments and guidance notes to align their processes and tools with the emissions objective, including the release in September 2023 of the "AER guidance on amended National Energy Objectives". Our understanding is that this will include a Value of Emissions Reduction (VER) to be published in November 2023 that DNSPs can use to incorporate emissions reductions in quantitative based decision making, such as expenditure business cases and Regulatory Investment Test for Distribution (RIT-D) assessments.

As these changes are occurring in parallel to this determination process it is difficult to fully capture and consider the impacts of this amendment. However, given that we must balance emissions reductions with other components of the NEO (safety, reliability, security and price), we consider the AER's draft decision expenditure allowances remain appropriate at the overall level. Within this allowance, we will re-prioritise capex where it is efficient to do so in support of emissions reductions related activities. (See further the capex discussion in Chapter 4.)

NSW Electricity Supply and Reliability Check-up

Following the NSW state election in March 2023, the NSW Office of Energy and Climate Change (OECC) commissioned the NSW Electricity Supply and Reliability Check-up Report (Check Up Report), released on 5 September 2023. The Check Up Report noted the speed at which the energy transition in NSW needs to occur in order to achieve the emissions reduction targets (a 50% reduction by 2030 and net zero by 2050).

Key recommendations included:

- identifying opportunities to increase the pace of decision making for the REZ program and delivery of the Central West Orana (CWO) REZ;
- identifying additional renewable generation projects that can be developed through small enhancements to the existing distribution and transmission networks;
- revisiting the methodology to recover Roadmap costs; and
- re-considering the exemptions framework to reduce the burden on residential customers.

The Check Up Report also observed the pressing need for greater CER integration in NSW to facilitate a speedy transition. The critical role that DNSPs have in providing a platform for the integration and use of CER (as the interface between CER and the broader energy system) was recognised in the NSW Government's acceptance of the following recommendation in the Check Up Report[3]:

> *That a NSW Consumer Energy Resources (CER) strategy be prioritised by the Department to better integrate CER into the supply mix by 2030. The strategy should ensure common technical standards for CER and set targets for uptake of technologies such as smart meters and distributed batteries.*

The NSW Government's response to the Check Up Report notes that its commitment to prioritise the development of a new Consumer Energy Strategy will *"further enable and better integrate the technologies supplied and purchased by households and businesses into the [electricity] supply mix"*, including small and medium scale solar and batteries, electric vehicle charging and smart appliances, and acknowledges that these technologies *"are essential to maintaining a reliable and affordable electricity supply"*[4].

We welcome these recommendations and any initiatives that will support the energy transition while maintaining system security and reliability at lowest cost to customers. The NSW Government's response to these recommendations is ongoing and may impact the services we provide and, therefore, our expenditure requirements. Examples could include the establishment of REZs within our distribution area and obligations to meet certain technology targets or provide services (such as essential system services).

In parallel, the NSW Labor Government released its first budget in September 2023 with a strong focus on accelerating the transition to renewable energy. This includes:

- **$1bn** to establish the Energy Security Corporation to invest in storage and firming projects including community batteries and virtual power plants;
- **$804m** to boost the State's renewal energy zones via the Transmission Acceleration Facility;
- **$264m** towards electric vehicle charging installations;
- **$121m** towards building community climate resilience; and
- energy rebates for families, seniors, low-income households and businesses to improve energy affordability.

In October 2023, the NSW Labor Government introduced the Climate Change (Net Zero Future) Bill 2023 legislating the NSW emissions reductions targets of 50% by 2030 and net zero by 2050 and establishing an independent Net Zero Commission.

Collectively, these policy decisions are a material change in circumstances that are likely to impact our role in providing distribution services over the coming years. (See further the service classification discussion in Chapter 4, setting out the changes that may be required to our service classification as these reforms progress.)

Federal Parliamentary Inquiry into residential electrification

On 14 June 2023 the Senate referred an inquiry into residential electrification to the Senate Economics References Committee for inquiry to report by the last sitting day of 2024. The Inquiry will broadly review Australia's residential electrification efforts to identify opportunities to optimise the cost and speed of the transition.

As noted in the NSW Check-up Report[5]:

> *Net Zero is premised on increased "electrification" of processes such as transport, heating, and cooking. For the first time in decades [the Australian Energy Market Operator (AEMO)] is projecting a growth in electricity demand. …*
>
> *Electrification will also mean that our lives become more, not less, dependent on electricity. This means the transition of the [NSW electricity] system must not be allowed to compromise the affordability or reliability of this increasingly critical essential service.*

[3] Marsden Jacob, NSW Electricity Supply and Reliability Check Up – Prepared for NSW Treasury – Office of Energy & Climate Change (OECC), 4 August 2023, p. 15
[4] Office of Energy and Climate Change, Electricity Supply and Reliability Check Up: NSW Government Response, September 2023, p 7.
[5] Marsden Jacob, NSW Electricity Supply and Reliability Check Up – Prepared for NSW Treasury – Office of Energy & Climate Change (OECC), 4 August 2023, p. 22.

We recognise the many economic, social and environmental benefits that electrification can deliver. Residential electrification offers a unique opportunity to empower all customers to reduce overall household energy costs. For example, research conducted by CSIRO and commissioned by Energy Consumers Australia (ECA) for its 'Stepping Up' report, found that residential electrification can provide annual saving of as much $2,250[6]. In addition to easing cost-of-living pressures on consumers, electrification can materially contribute to the achievement of Australia's decarbonisation ambitions.

We also acknowledge the challenges that exist in delivering the benefits of electrification in a timely, equitable and efficient manner, noting the key recommendations from ECA's 'Stepping Up' report which highlighted the need to ensure the following[7]:

- Households need to have agency – Australians continue to take-up solar at world leading rates. We must continue to support the ability of households to be an active part of the energy transition by providing them with the right information at the right time to empower them to make decisions about how to electrify their homes to suit their needs.
- Electrifying households must be done equitably – households that face barriers to electrifying their homes need support, including financial support to assist with the upfront costs of electrification. All households must be able to electrify if Australia wishes to meet its emissions reduction goals.

Federal Budget

The Federal Government's 2023-24 Budget (announced on 9 May 2023) included several energy related initiatives focused on accelerating and supporting the Net Zero transition, including the following:

- **Energy Savings Plan:** This includes a $1.3bn Household Energy Upgrades Fund, with $1bn to the Clean Energy Finance Corporation (CEFC) and $300m to social housing, to help finance and support household energy upgrades to improve energy efficiency.
- **Hydrogen Headstart:** The Government will provide $2bn of revenue support to competitively tendered hydrogen production contracts targeting a gigawatt of electrolyser by 2030. There will also be $38m in funding for a Guarantee of Origin scheme to certify and track emissions from clean energy products focussing on hydrogen.
- **National Net Zero Authority:** The Government will legislate a national Net Zero Authority to support the net zero emissions target. The Authority will focus on supporting and re-skilling workers in emissions-intensive sectors, coordinate programs across government and support investors and companies in transformation opportunities.
- **Continuation of existing programs:** The Government re-affirmed its commitment to the 'Capacity Investment Scheme' with the 2023-24 Budget providing funding for the initial auctions and underwriting of the investment. In addition to the 'Power the Regions Fund' which includes $600m in funding for trade-exposed safeguard facilities, $400m in to support primary steel, cement, lime, aluminium and alumina industries and $400m to be administered by ARENA supporting regional industrial facilities and new clean energy industries.

AEMC metering review

On 30 August 2023, the AEMC released its final report in relation to its review into the contestable metering framework, which included the following key recommendations[8]:

- DNSPs will need to develop a Legacy Metering Retirement Plan (LMRP) to be approved by the AER by 31 March 2025. The LMRP will need to include a schedule of meters to be retired over 2025-30 with annual targets of 15-25% of total meters to be churned and an array of site-specific information to be provided to metering parties on a best endeavours basis.
- Retailers will have to comply with the annual LMRP targets on a best endeavours basis with exceptions subject to the AER's assessment of them as reasonable via annual reporting. The AEMC recommend civil penalties apply to meeting the overall 2030 target. A change to the

[6] CSIRO, Future savings for all-electric households [website], https://www.csiro.au/en/news/all/articles/2023/august/energy-transition-savings, accessed (10 November 2023).
[7] ECA, Stepping Up: A smoother pathway to decarbonising homes, 10 August 2023, p. 2
[8] As a rule change request has been lodged to enact these recommendations, these are subject to change via the rule change process.

LMRP, via an application to DNSPs, can only be triggered by material, exogenous and unforeseen event(s).

- Customers remain responsible to remediate sites to facilitate meter churns, however they cannot be obligated to do so. The AEMC continue to recommend jurisdictional governments develop financial support measures for remediation work.
- Basic Power Quality Data (PQD) will be provided free of charge to DNSPs and provided at least daily. Advanced PQD will continue to be negotiated between parties.

Given the timing of the AEMC's final report, the AER did not have sufficient time to amend its draft decision to account for this material change in circumstance, and has noted that it is open to DNSPs proposing a reclassification of services to account for this change as part of their revised proposals[9]:

> *Because of this change we are open to the reclassification of legacy metering services from alternative control services (ACS) to standard control services (SCS) in the final proposals (and all future regulatory proposals) to better socialise these costs and recognise the network benefits of this transition.*

We consider reclassifying Type 5 & 6 Metering Services will better promote the NEO and cater for the transition to smart metering that the AEMC's recommended changes seek to accelerate. (See further the discussion in Chapter 4 for how we have addressed these proposed metering reforms.)

[9] AER, Draft Decision – Endeavour Energy Electricity Distribution Determination 2024 to 2029 – Overview, 28 September 2023, p.ix.

3. Customer-Focused Decision Making

3.1. Overview

We have undertaken our most comprehensive and ambitious engagement program to ensure that our plans reflect the service priorities our customers have told us are in their long-term interests. We've kept downward pressure on network charges, simplified tariffs for retailers, and priced streetlighting and smart cities technologies to support councils.

3.1.1. Our engagement approach and findings

Our January 2023 Proposal detailed our comprehensive engagement approach which was co-designed with our Board, Executive and customer and stakeholder representatives. This engagement was highlighted by the formation of a Regulatory Reference Group (RRG) as a sub-committee of our Peak Customer and Stakeholder Committee (PCSC) which worked collaboratively on the development and implementation of our engagement plan and the development of the 2024-29 Proposal.

This process led us to commit to engagement that is:

Led from the top, with significant commitment from and involvement of the Board and our Executive.

Integrated with a broader uplift in customer focus and engagement across Endeavour Energy's business.

Co-designed with customer advocates, including the engagement design and the development of proposal itself.

Comprehensive, including expanded representation of and engagement with informed stakeholders via Endeavour Energy's PCSC and three supporting sub committees - the RRG, the Future Grid Reference Group (FGRG) and the Retailer Reference Group (ReRG). We also removed barriers to participation with some RRG and FGRG members being remunerated for their time to ensure the right capabilities and experience across the members.

Inclusive, featuring more engagement with a Culturally and Linguistically Diverse (CALD) group and Aboriginal and Torres Strait Islander (ATSI) consumers, including, for the first time, in-language engagement and expanded social programs.

Proactive, particularly in relation to our engagement with the AER and via the Early Signal Pathway under its Better Resets Handbook.

Upfront, providing an early indication of Endeavour Energy's key positions through the publication of Preliminary Proposal that will inform future engagement.

Collaborative, working closely with other distribution networks and agencies on issues of common interest to our stakeholders (e.g., resilience) but also taking a coordinated approach to respect the time of stakeholders participating in multiple regulatory processes.

To ensure appropriate breadth and depth of engagement, the RRG, together with representatives of Endeavour Energy’s Board and our Executive Leadership Team co-designed a map of issues for engagement, identifying their impact on the proposal and the ability of customers to influence the outcomes for each aspect of our revenue proposal on the IAP2 Spectrum of Participation.

We also utilised a variety of engagement methods and channels to ensure the overall regulatory engagement program achieved both deep and broad engagement with a diverse cross-section of customers and stakeholders in accordance with the expectations of the Better Resets Handbook (BRH).

The chart below summarises the five phases of our engagement program, noting that recommendations of the RRG Independent Members Panel are reflected in:

- the augmentation of the fourth “Refine” phase, in order to sense-check potentially changing customer preferences; and
- the addition of the fifth “Confirm” phase to cover the period following the submission in January 2023 of the Proposal, in response to concerns that customer views may materially shift in response to the ongoing energy transition and increasing cost-of-living pressures.

Figure 3-1 Endeavour Energy 2024-29 Engagement program summary

Preparation	Phase 1 Discover	Phase 2 Explore	Phase 3 Prioritise	Phase 4 Refine	Phase 5 Confirm
Oct 2020 – Mar 2021	Apr 2021 – Sept 2021	Oct 2021 – Apr 2022	May 2022 – Oct 2022	Nov 2022 – Jan 2023	Feb 2023 – Jul 2023
A period of forward-planning to prepare Endeavour Energy for the launch of the regulatory cycle	A research period to better understand customer and stakeholder needs and preferences to help shape our engagement approach	A period of deeper exploration of key issues to help inform the development of our Preliminary Proposal	Broad and deep engagement on our Preliminary Proposal, identifying aspects of greatest importance to customers	Developing and refining our Final Proposal using insights from the previous phase	Confirming our customers’ priorities in the context of a changing economic environment
• Benchmarking previous engagement with best practice • Engagement partner appointed • PCSC membership enhanced	• Establishment of RRG, FGRG and ReRG and determine the Terms of Reference • Board/Executive/ customer co-design workshop • RRG engagement planning • Joint DNSP engagement (emerging services) • Future Grid workshop • Co-designed exploratory research straw man • Board check-in • PCSC • Exploratory research (residential) • Exploratory research – SME (Dinners with Endeavour) • Exploratory research (CALD) • Ongoing engagement with AER	• RRG and AER Investment Value Framework • BAU State of the Network Forum (Illawarra and South Coast) • BAU State of the Network Forum (Greater Western Sydney) • High-energy users’ workshop • Future Grid workshops • RRG • PCSC x 2 • Joint DNSP engagement (tariffs) • Ongoing RRG mini Deep Dives • Board check-in • Commence engagement of AER’s CCP • Ongoing engagement with AER • One-on-one briefings with stakeholders • RepTrak benchmarking study	• Local Council Workshop (Illawarra and South Coast) • Local Council Workshop – Western Sydney) • Customer Panel Wave 1 • Customer Panel Wave 2 • Deep Dive 1 • Deep Dive 2 • One-on-one briefings with stakeholders • Quantitative survey • RRG webinars x 3 • PCSC x 3 • Ongoing RRG mini Deep Dives • In-language direct engagement with CALD communities • Customer Panel Wave 3 • Ongoing engagement with AER	• Stakeholder check-ins • Individual retailer engagements • Local council workshop (street lighting tariffs check-in) • RRG bi monthly meetings • RepTrak benchmarking study	• Customer Panel check-in • Stakeholder check-in • RRG bimonthly meetings • AER public hearing
	• Engagement Plan • Exploratory Customer Research Report	• Preliminary Proposal • Business Narrative	• Draft Proposal • Engagement Summary Report	• Final Proposal • Final Proposal Customer Overview	

Our Engagement Summary Report (refer to Attachment 5.01 of our January 2023 Proposal) provides a comprehensive overview of the design and execution of our Engagement Plan. To summarise, two key challenges emerged to manage from the feedback we received:

1. **Actively supporting the empowerment of customers** through an equitable transition to renewable and decentralised energy whilst managing the increasing risks of climate change to network and community resilience; and
2. **Providing value for money services,** in the context of increasing energy prices and cost of living pressures, that meets customers' service expectations through a constrained expenditure allowance that promotes efficiency and innovation.

Our findings, broadly speaking, suggested our Preliminary Proposal struck an appropriate balance between these competing priorities. We made a series of targeted adjustments in our Draft Proposal and January 2023 Proposal in response to our engagement findings to refine our tariffs and engagement plan, uplift our resilience and innovation investment and further constrain overall costs.

3.2. Assessment of our engagement and key learnings

Our January 2023 Proposal set out our assessment approach, including evaluation survey results and broader reflections of our key learnings. The feedback on our engagement approach has been consistently positive and highly rated, recognising that improving our ability to adapt our engagement program to a fast-changing environment and managing engagement fatigue were identified as areas for future improvement.

The RRG, through a number of reports, noted several aspects of our engagement program have been of a high quality:

With the assistance of SEC Newgate, Endeavour has undertaken an engagement programme that, in our view, has been extensive and multifaceted.

From an Independent RRG perspective, we acknowledge that Endeavour has given us ample opportunity to work with them in the design and execution of the engagement, asked for and considered our advice and challenges, and sought to respectfully engage with consumers with a high degree of detail.

Endeavour Energy has addressed each of the issues we raised in our August report. This includes an increased focus on affordability and options that provide customers with value for money, and the need to adapt engagement to reflect a fast-changing social environment and increasing energy costs.

Overall, we consider Endeavour Energy has met the guidelines of the AER's Handbook in the development and execution of its engagement process. This observation results from our extensive involvement in the development of the Draft Proposal to date, but more importantly reflects our first-hand observation of Endeavour Energy's commitment to an accessible, wide-ranging, clear and transparent engagement process and their willingness to share information early on and to listen and respond to feedback.

This being the first time the BRH process has been conducted, we commissioned an additional independent assessment of our engagement program conducted by industry expert Clare Petre. This report supported the views of the RRG that the[10]

> *Reset proposal was a world away from the previous more adversarial and defensive Reset experiences. Customer engagement was genuine, authentic, sincere, active, and positive. The codesign model was successful.*

3.2.1. AER Draft Decision Findings

Following the lodgement of our Proposal in January 2023, we engaged extensively with the AER on a series of information requests. In doing so we sought to respond promptly to both the AER's technical questions and the feedback received in submissions to the Proposal. This led to further refinements to our Proposal, particularly with respect to our proposed Public Lighting and ANS prices.

The AER's draft decision noted additional feedback from the AER's Consumer Challenge Panel (CCP), Urban Development Institute of Australia (UDIA) and Public Interest Advocacy Centre (PIAC) that supported the quality of our engagement program. We also acknowledge PIAC's

[10] Endeavour Energy – Clare Petre Consulting, 5.17 Independent assessment of consumer engagement, November 2022, p. 3.

recommendation that Endeavour Energy improve its ability to make dynamic adjustments to its engagement program for an evolving environment.

The AER's draft decision acknowledges that Endeavour Energy has met the expectations of the BRH and conducted a high-quality engagement program that has been a key factor in the AER's broad approval of our January 2023 Proposal. The AER notes:

Endeavour has provided a high-quality proposal, which it developed through an extensive, genuine and high-quality engagement process. Endeavour has also engaged constructively with us through information requests to allow us to better understand the drivers of its proposal and to close gaps in its supporting information.

We observe that Endeavour has demonstrated a significant step-up in consultation with customers and stakeholders, in accordance with Handbook expectations. There has been broad and deep engagement with customers and stakeholders across the reset process that has genuinely influenced the proposal through a co-design process. This has been acknowledged by a variety of stakeholders and their representatives, including the Regulatory Reference Group (RRG) independent advisory panel of experts appointed by Endeavour, an independent engagement expert appointed by Endeavour as part of the Handbook process, the Endeavour Customer Panel, and the Consumer Challenge Panel, sub-panel 26 (CCP26). Endeavor's consumer engagement has been a material factor in our decision to accept most of Endeavour's proposal.

We also commend Endeavour on the significant step-up taken relation to engagement with its stakeholders on issues such as public lighting. Endeavour openly and genuinely engaged on matters raised by stakeholders responding to its initial public lighting proposal in order to seek resolution on them for our draft decision. We commend Endeavour in its engagement approach to deliver outcomes valued by its stakeholders.

3.3. ‘Confirm’ Phase approach and findings

3.3.1. Our approach

As noted above, we augmented our engagement program to include an additional phase to confirm the findings from earlier in our engagement program. This phase was added at the suggestion of our RRG in response to concerns that customer views may materially shift over the course of this determination process in response to the ongoing energy transition and increasing cost-of-living pressures.

Relatedly, many stakeholders, including Clare Petre, commended Endeavour Energy’s Customer Panel and its retention rate. We have been encouraged to refresh and continue this initiative over the long-term but also to continue engaging with the group of customers who have been on a significant journey with Endeavour Energy.

As part of good practice engagement, we also see the value in continuously engaging with our customers to understand their preferences and values. Doing so over time provides additional insight in surfacing preferences that are subject to change compared to those that remain constant in a changing environment.

The ‘Confirm’ Phase involved the following activities:

- **RRG engagement**: we continued discussions with the RRG on a range of matters over several sessions following our January 2023 Proposal. This included consulting on our proposed Security of Critical Infrastructure (SOCI) Act compliance program, which was quantified and finalised post-January, collaborating on our Customer Panel ‘Confirm Phase’ engagement design and on the question of metering service re-classification.
- **Retailer RRG engagement:** we continued to consult with our Retailer RRG with a focus on outstanding matters of our TSS, particularly the transition period to cost-reflective tariffs and on the matter of metering re-classification.
- **Customer Panel ‘Wave 4’**: on 7 June 2023 we conducted a 4th wave of consultation with our Customer Panel to loop back on our January 2023 Proposal (what changed, and why), check-in on customers current views on affordability, sense-check our Proposal against the changing economic environment and seek further views on our tariff transition window.
- **Targeted stakeholder discussions**: a number of formal submissions made to our January 2023 Proposal with a focus on EV and embedded network tariffs and Public Lighting. We met with interested stakeholders such as the Western Sydney Regional Organisation of Councils (WSROC) to discuss their submissions and propose solutions to address the concerns raised.

3.3.2. Our findings and response

This phase of our engagement program generally confirmed that our January 2023 Proposal continues to strike the right balance in managing competing priorities of affordability and reliability with emerging areas of resilience and innovation. This was best highlighted by 96% of our Customer Panel remaining of the view that our January 2023 Proposal reflects their priorities and preferred outcomes and is in the long-term interests of customers.

At the same time, the results showed elevated concerns about cost-of-living pressures and a stronger focus on affordability. Reflecting this, customers re-ordered their priorities with an increased interest in Endeavour Energy helping them get information on how to save on electricity bills by managing their consumption and where to go for wider energy support (financial and advice).

Refer to Attachment 0.02 for a full summary of our ‘Wave 4’ engagement results.

In the table below we summarise the key feedback we received during this phase of our engagement program and how we have responded in this Revised Proposal.

Table 3-1 Summary of Endeavour Energy 2024-29 'Confirm' phase engagement findings and response

Key Findings	What we heard	How we have responded
Affordability and value for money	• The majority of customers and stakeholders considered our January 2023 Proposal reflected their priorities and preferred outcomes. • Most customers and stakeholders had growing concerns about cost-of-living pressures. • Some stakeholders raised general efficiency concerns in response to our January 2023 Proposal[11].	• We have continued to adopt a constrained approach to investment in the delivery of priority customer services, tightly managing the costs we can control to keep our contribution to customer bills as low as possible despite rising external pressures driving up our costs including interest rates. • Since the lodgement of our January 2023 Proposal, we have quantified additional SOCI implementation related expenditure, emissions reduction and CER hosting spend. We also continue to experience significant cost increases on augmentation projects due to the global economic downturn and further step changes to our operating costs are likely with ongoing regulatory changes. However, we remain committed to absorbing and managing these cost pressures within the AER's draft decision allowance given rising affordability concerns.
Tariffs	• Two thirds of Customer Panel participants would prefer a 12-month transition rather than a 24-month transition to cost-reflective tariffs. This was driven by a desire to save money sooner rather than later. • Most customers were keen to be provided with more information on how they could change their consumption to benefit from cost-reflective tariffs. • Several stakeholders made submissions to our January 2023 Proposal questioning the evidence base supporting the newly proposed export and embedded network tariffs and the potential impacts these tariffs could have on customers[12]. For EVs, Evie Networks[13] raised concerns with the impacts 'traditional' network tariffs will have on the EV sector.	• We are working with retailers to transition customers with smart meters to cost reflective tariffs, and we will support this change by conducting the transition over a 12-month period to help customers understand their energy usage and adjust their behaviour to take advantage of cost reflective tariffs and by working with retailers to understand what educational support customers need to make a smooth transition to cost reflective tariffs. This represents a change to our January 2023 Proposal for a 24-month transition period. • We are proposing new tariffs for emerging technologies and embedded networks to provide cost-reflective price signals to customers in accordance with the pricing objectives of the Rules to support informed decision-making and equitable cost recovery. After careful consideration, we have made targeted adjustments to our proposed embedded network tariff to better reflect the potential benefits they offer Endeavour Energy customers. We also will investigate trialling an EV specific controlled load tariff over the 2024-29 period.

[11] Submissions from: Origin Energy – Submission – 2024-29 Electricity Determination – NSW and ACT – May 2023; Energy Australia – Submission – 2024-29 Electricity Determination – NSW and ACT – May 2023.
[12] Submissions from: Solar Citizens – Submission – 2024-29 Electricity Determination – NSW DNSPs – May 2023; Caravan & Camping Industry Association NSW – Submission – 2024-29 Electricity Determination – Endeavour – May 2023.
[13] Submission from: Evie Networks – Submission and attachment – 2024-29 Electricity Determination – NSW – May 2023.

Key Findings	What we heard	How we have responded
Keeping customers at the centre of our decision making	• Several stakeholders remain focused on embedding our improved engagement approach into business-as-usual activities.	• Our increased commitment to customer and stakeholder engagement is being adopted as part of our business-as-usual approach. Plans are in place to review the learnings from this regulatory engagement period and to embed the structures, processes and channels required to ensure high quality engagement sits at the core of what we do. • We have also pursued better engagement across all sectors of the energy industry as one of the original signatories to The Energy Charter, committing to work collaboratively to achieve better customer outcomes. Endeavour Energy has actively contributed to Energy Charter #BetterTogether Teams which this year resulted in 2,000 fewer customers being disconnected; helped to rebuild trust across CALD communities by engaging in-language and in-community; and partnered with other signatories to build a community of practice that promotes deeper understanding and improved responses to customer and community engagement.
Smart cities and communities (streetlighting / councils)	• Following positive engagement and broad acceptance of our Public Lighting Pricing methodology and outcomes in advance of our January 2023 Proposal we received addition feedback via submissions to our Proposal from Western Sydney Regional Organisation of Councils (WSROC) and Wollondilly Council[14]. These submissions highlighted several concerns with Public Lighting pricing across the NEM and provided benchmarking analysis of Endeavour Energy's propose prices. • Councils also remain interested in rapidly transitioning to more energy efficient public lighting.	• Prior to the AER's draft decision we submitted revised, and materially lower, public lighting prices in response to the additional feedback we received. We have otherwise maintained our underlying assumptions with respect to failure rates, cleaning cycles and asset lives where these are supported by data and industry standards. • We are making new technology for public lighting more affordable, while also delivering significant energy savings to local councils. • We have updated our Public Lighting Modelling approach to simplify it so that new technologies can be transparently priced and more quickly introduced over the course of a regulatory period.
Metering Services	• Some stakeholders, including the AER and RRG, expressed concerns that an accelerated metering transition could result in exponentially increasing prices for our legacy metering services. This outcome would disproportionately affect vulnerable customers who would be late adopters of smart meters as they may not be able to afford potential site rectification costs, live in remote areas or do not control their household energy decisions (e.g., public housing).	• The AER's draft decision maintains an ACS classification of Type 5 & 6 Metering Services as the AEMC's metering review was finalised in parallel to their draft decision. While the AER has taken steps to address these concerns in its draft decision we remain of the view that a re-classification to SCS would better do so. We therefore propose to re-classify Type 5 & 6 Metering Services as SCS for 2024-29.

[14] Submissions from: WSROC – Submission – 2024-29 Electricity Determination – Endeavour – May 2023; Wollondilly Shire Council – Submission – 2024-29 Electricity Determination – Endeavour Energy – May 2023.

4. Detail of Revised Proposal

4.1. Overview

We largely accept the AER's Draft Decision and have only updated it to the extent necessary to reflect the latest available information.

The AER's draft decision accepted most aspects of our January 2023 Proposal and subsequent amendments to our ANS and Public Lighting prices. It also updated several aspects of our Proposal for the latest available information or amended our Proposal in relation to the following:

Inflation: The AER updated our proposed CPI forecast of 2.87% to 2.80% based on the RBA's August 2023 Statement on monetary policy in accordance with its approach to the regulatory treatment of inflation[15]. This affects several calculations within our revenue requirement, most notably the return of capital and revenue adjustments for incentive scheme outcomes.

WACC: The AER updated our proposed WACC from an average of 5.99% to 6.00% based on the latest available information (up until June 2023) and the final RORI which was released in February 2023. This included updates to both the cost of debt and equity and the value of imputation credits. This resulted in changes to our return on capital and corporate income tax allowances.

Innovation Fund: The AER did not allow the $5 million (real; 2023-24) of opex associated with the Innovation Fund (which had been proposed as a revenue adjustment). However, in light of the significant constraints that had been applied to other categories of our capex forecast, the AER did not remove the capex associated with the Innovation Fund. Whilst the AER did not consider the Fund could be formally approved in its draft decision in accordance with the Rules, it did encourage Endeavour Energy to fund innovation through offsetting efficiencies within the 2024-29 expenditure allowances.

Tariff Structure Statement: The AER was complimentary of our proposed TSS and highlighted a few areas for us to consider further and/or improve upon in our Revised Proposal in response to stakeholder feedback.

Pass-Throughs: the AER did not consider our proposed amendments to the 'natural disaster' nominated pass-through event were necessary and that our suggested considerations are appropriately captured by the existing definition that the AER typically applies.

Our Revised Proposal accepts most aspects of the AER's draft decision and continues to balance providing value for money services while addressing stakeholder and customer priorities of supporting innovation, customer choice, network resilience and customer growth. In working towards a proposal that best serves the long term interests of customers, we have been guided by our ongoing engagement with the AER, customers and stakeholders, and have reflected on our extensive engagement program and commitment to the expectations of the AER's BRH. We have also built on the significant improvements we have made over the last few years to our operating efficiency and service quality. Aligned with this approach, our Revised Proposal:

- accepts most components of the AER's draft decision and updates several aspects where more up to date information is available;

[15] AER, Final position – Regulatory treatment of inflation, December 2020, p. 6.

- accepts most components of the draft decision with respect to our TSS and updates it in response to the AER's highlighted areas;
- confirms our commitment to the principles of the Innovation Fund, which was strongly supported by customers and stakeholders. To continue to find a better way of doing things in a period of rapid technological change, we still intend to establish a committee akin to the Innovation Fund to explore and consult on innovative technologies and solutions with customers and stakeholders within the 2024-29 expenditure allowances; and
- includes an amendment to re-classify Type 5 & 6 Metering Services from ACS to SCS following the AEMC's final metering review outcomes as well as highlighting further changes to the AER's service classification draft decision that may be warranted due to this and other ongoing policy matters.

The main SCS[16] building block components of our Revised Proposal indicative annual revenue requirements for the 2024-29 period are $5,201.8 million (real, 2023-24) (1.0% higher) than the AER's draft decision and outlined in the table below. The increase is primarily due to updating our Proposal for actual FY23 performance. The higher than forecast capex for FY23 has increased our return on and of capital allowances and is the result of increasing cost pressures we are facing following the global economic downturn and an acceleration of some key growth projects such as the Western Sydney Aerotropolis.

The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2024-25 to 2028-29 are outlined below:

Table 4-1 Revised standard control revenue requirement over the FY25-FY29 regulatory control period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Return on capital	468.6	469.2	472.9	475.5	479.9	**2,366.1**
Return of capital	282.8	235.1	217.0	191.4	174.0	**1,100.3**
Operating expenditure	287.6	294.4	297.9	304.8	311.8	**1,496.6**
Cost of corporate tax	26.6	19.9	19.0	17.7	15.7	**98.9**
Revenue adjustments	55.7	22.3	41.2	8.3	0.7	**128.3**
Total unsmoothed revenue	1,121.2	1,041.0	1,048.1	997.7	982.1	**5,190.2**
Main SCS smoothed revenue	988.6	1,075.6	1,060.6	1,045.8	1,031.2	**5,201.8**
Metering SCS smoothed revenue	18.8	18.0	17.3	16.6	15.9	**86.5**
Total SCS smoothed revenue	1,007.4	1,093.6	1,077.9	1,062.4	1,047.1	**5,288.4**

We expect further updates will be required at the time of the AER's final decision for key inputs such as the WACC and forecast inflation. In the following sections we provide a more detailed summary of our Revised Proposal by key component.

[16] Exclusive of Type 5 & 6 Metering services for comparison purposes.

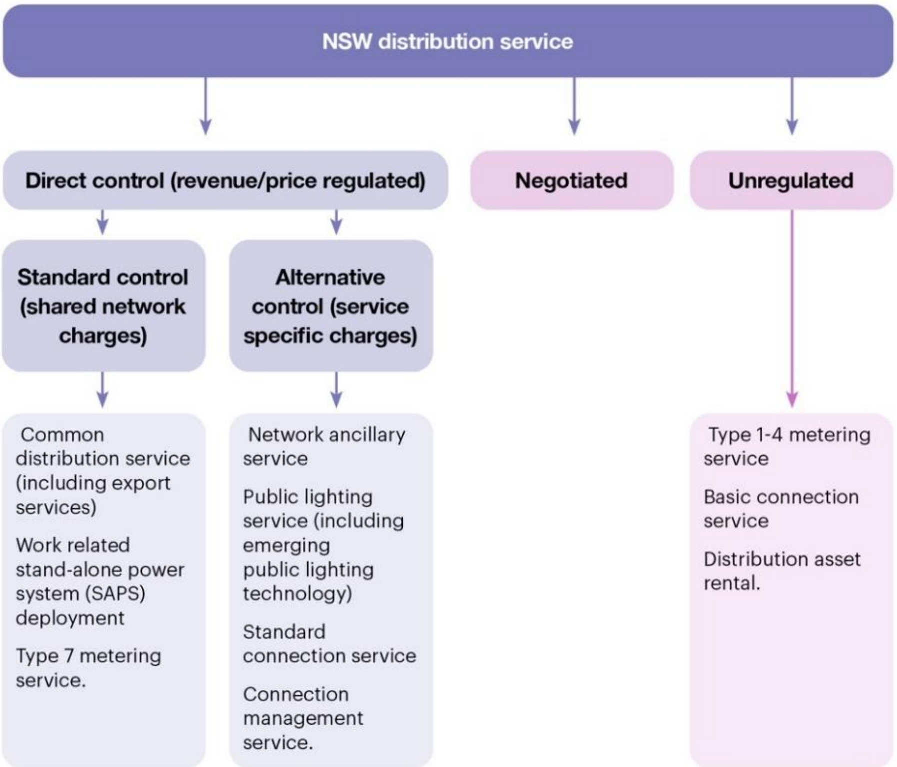
4.2. Revised Proposal Detail

This chapter sets out our response to the AER's draft decision by key constituent decisions and building blocks.

4.2.1. Service Classification

The AER's draft decision applied the service classification as set out in the final Framework and Approach (F&A) decision for the 2024-29 period as outlined below.

Figure 4-1 AER service classification summary for the FY25-FY29 period



We propose the AER review and amend its F&A decision for material changes in circumstances with respect to metering and energy transition related services.

Metering services

For metering, an accelerated transition to smart meters exposes our Type 5 & 6 metering customers to increasing prices. This is because our metering costs will be recovered from a rapidly reducing customer base. In our January 2023 Proposal the metering price for residential customers increased from $32.67 in 2024-25 to $48.60 by 2028-29.

The AEMC's metering reforms would accelerate the transition thereby worsening the pricing outcome from our January 2023 Proposal. This risk can be addressed by either:

1. Recovering all metering costs from all existing and historical Type 5 & 6 metering customers (i.e., remains an ACS).

Currently as an ACS the Metering Asset Base (MAB) is recovered from all customers who have a Type 5 & 6 meter or did so prior to 1 July 2015 and the operating costs (i.e., non-capital) are recovered from all existing Type 5 & 6 customers. This results in a 'capital' charge in the order of $2 per annum and an 'non-capital' charge in the order of $33-$49 per annum for residential customers. It is the latter that increases rapidly as the customer base transitions to smart metering.

Removing this distinction between 'capital' and 'non-capital' charges reduces this risk. It would involve all customers who either have or had a Type 5 & 6 meter prior to 1 July 2015 paying a combined metering charge. This approach was adopted by the AER in its draft decision and results in a metering charge in the order of $20-$22 per annum for residential customers.

2. Recover all metering costs from all customers (i.e., it becomes a SCS)

The alternate is an extension of the above whereby all metering costs are recovered from all customers rather than just all current or historic Type 5 & 6 customers. Like the above approach it is not cost-reflective as metering costs are recovered from both non-metering customers and metering customers alike. However, it is a more effective solution to addressing the equity issue created by an accelerated metering transition. This approach results in a metering charge in the order of $10-$13 per annum.

We are open to stakeholder views as to what the best approach is in consideration of the above pricing outcomes and note that these approaches are revenue neutral. Our position is that there is more value in addressing the equity issues associated with an accelerated smart metering transition then providing a cost-reflective price signal for a soon-to-be replaced technology. This is aligned with the AER's draft decision which notes[17]:

> *…we consider a reclassification of legacy metering services as standard control services (SCS) and with costs recovered through the revenue cap is likely to be more appropriate in the revised proposals in order to reduce material price impacts for customers through the metering transition. Contribution by all customers is appropriate as all energy users will recognise the network benefits of this transition.*

In order to address this risk, and support the smart metering transition, we therefore propose that the AER:

1. Re-classify Type 5 & 6 Metering Services as a SCS.
2. Separate works to re-seal and/or unlock a Type 5 & 6 meter and changing a distributor load control relay channel from the above re-classification so that it remains an ACS.
3. Amend the 'Contestable metering support roles' service definition.

Energy transition services

For energy transition related services, we are committed to supporting the ongoing take-up of decentralised and decarbonised technology by our customers. We must be able to adapt to these changes in both the services we provide and the way in which we provide them. The regulatory framework effectively 'locks in' the services we provide for a five-year period. It is therefore critical that the service classification listing is up-to-date and, to the extent possible, flexible to changes in our obligations and role.

Given several developments that have occurred since the F&A was finalised in July 2022, we propose that the AER:

1. Clarify 'leasing of excess battery capacity' is a distribution service and leave it as unclassified.
2. Clarify 'essential system services' are distribution services and leave them as unclassified.
3. Clarify 'leasing of property or asset capacity for EV charging infrastructure' is a distribution service and leave it as unclassified.
4. Classify 'provision of network data' as an SCS and amend the scope of the 'Customer requested provision of electricity network data' ACS.
5. Clarify the treatment of Distribution REZ's as inputs to or distinct distribution services.
6. Monitor whether additional electrification services should be classified prior to the AER's final decision subject to further policy changes.

Attachment 0.03 to this Revised Proposal contains the rationale for these changes and the proposed amendments to the AER's service classification table.

[17] AER, Draft Decision – Endeavour Energy Electricity Distribution Determination 2024-to 2029 – Attachment 20 – Metering Services, 28 September 2023, p. 3

4.2.2. Control Mechanism and Formulae

In our January 2023 Proposal we accepted the decisions in the AER's Final F&A to apply revenue caps to SCS and price caps to ACS. We also proposed to apply the AER's final position on the side constraint mechanism and the formulae to give effect to the control mechanisms set out in the Final F&A.

The AER's draft decision made a number of amendments to improve the transparency of the revenue cap formulae, give effect to its final position on side constraints and amend the ACS formulae to accommodate a true-up for metering service opex amongst other minor changes. We accept the AER's draft decision noting that further updates will be required if Type 5 & 6 metering is re-classified from ACS to SCS as proposed.

In preparing this Revised Proposal, we have had several discussions with the AER on how the revenue cap control mechanism formulae could be updated for a re-classification of metering services. We understand the AER's preference is for legacy metering services to be treated as a separate sub-component of total SCS expenditure and the outputs of "main SCS" (i.e., SCS excluding metering) and legacy metering SCS PTRMs be consolidated at the total level for the purposes of the AER's constituent decisions.

This means there will be two different smoothing processes to accommodate different priorities in smoothing across main SCS and legacy metering SCS. The AER has also set out its expectation that legacy metering SCS revenue should be recovered across all customers as a separate fixed charge component that the TSS should be updated to introduce. This would be to maintain transparency and accommodate any true-ups or pass-throughs that may be required.

We agree with the AER's principles for incorporating legacy metering into SCS, particularly the need to balance transparency with pragmatism. However, we propose an alternate means for giving effect to the reclassification of metering.

Specifically, the AER's preferred approach requires the calculation of an additional Total Annual Revenue (TAR) specifically for metering and in addition to the TAR calculated for main SCS services. The calculation of a metering TAR essentially replicates the formula used to calculate the main SCS TAR. The total TAR would involve combining the legacy metering SCS TAR with the main SCS TAR. We propose a less complicated approach is taken whereby legacy metering revenue is incorporated in the main SCS TAR via an adjustment factor.

There are currently adjustment factors for incentive scheme revenue ("I"), overs and unders balancing ("B") and cost pass-through amounts ("C"). We propose a legacy metering adjustment factor is added to the formulae (an "M" factor). This would reduce the complexity of implementing a change in classification by avoiding the need to separate Distribution Use of System Charges (DUOS) in billing systems i.e., main SCS DUOS and metering SCS DUOS. On this, we are yet to fully scope the ICT changes required to implement the AER's preferred approach and whether it is feasible or cost-effective.

Our alternate approach would still allow for the separate smoothing of legacy metering revenue as the AER has discretion in how the adjustment factor is calculated (in this instance by replicating the approach taken to calculating and smoothing revenues in the PTRM). DNSPs would also still be able to adjust their TSS's, for the AER to review and approve accordingly, to specify how this component of revenue will be recovered from customers.

We note this would not allow for separate management of an overs and unders account. However, in our view there is no practical value in doing so given we propose to recover legacy metering revenue on a per customer basis. The level of forecasting error in customer numbers is historically low (0.3% per annum over the five-year period 2019-2023, inclusive) and therefore the contribution of metering to over or under recoveries is likely to be immaterial (in the order of cents per customer). Instead, for reporting purposes the SCS revenue attributable to metering could be reported by networks, similar to incentive scheme revenue in the Benchmarking RIN currently, so that the AER is able to separate it for reporting and benchmarking purposes as required.

Our proposed approach also avoids a number of potential compliance issues associated with duplicating the approach taken to deriving TAR an AAR amounts and setting tariffs for SCS legacy metering in accordance with the Pricing Principles in the Rules. These issues include the determination of long run marginal cost estimates for metering SCS (6.18.5), stand-alone and avoidable costs for metering SCS (6.18.5) and the application of the side constraint mechanism to metering SCS (6.18.6).

Under our proposed approach, the metering SCS would be folded into main SCS services for the purposes of Rule compliance, noting that the side constraint formula would also need to be adjusted for the M-factor. For these reasons we propose our alternate method for amending the revenue cap control mechanism formula for giving effect to a change in service classification for metering.

We would welcome further engagement with the AER on this proposal to develop an approach that is proportionate and promotes transparency and pragmatism.

4.2.3. Incentive Schemes

Application of incentive schemes

We accept the AER's draft decision to apply the following incentive schemes to Endeavour Energy for the 2024-29 period:

- Efficiency Benefit Sharing Scheme (EBSS);
- Capital Efficiency Sharing Scheme (CESS) noting as per the updated capital expenditure incentives guideline;[18]
- Service Target Performance Incentive Scheme (STPIS) noting the customer service component will be replaced by a bespoke Customer Service Incentive Scheme (CSIS); and
- Demand Management Innovation Allowance Mechanism (DMIAM) and Demand Management Incentive Scheme (DMIS).

We also confirm our position not to propose an Export Service Incentive Scheme (ESIS) for the 2024-29 period.

We accept the parameters, incentive rates, revenue at risk, exclusions and targets for each of the respective schemes outlined above (as applicable) as set out in the AER's draft decision. We have only updated the AER's draft decision to the extent necessary to update the STPIS and CSIS targets for the latest available information (e.g., FY23 actual performance). Refer to Attachments 0.16 to 0.18 for these proposed revisions, for the latest available information, to the STPIS and CSIS.

4.2.4. Revised Revenue Building Blocks

Revised Regulatory Asset Base (RAB) values

The AER accepted our methodology for determining opening and closing RAB values in its draft decision and updated our Proposal for the latest inflation inputs. The AER also accepted our proposed addition of two asset classes (short-term and long-term leases) to reflect changes to AASB16, which requires the present value of future lease payments to be capitalised.

We accept the AER's methodology and have updated the AER's draft decision for our actual FY23 performance. This involved updating the draft decision roll-forward model (RFM) for actual capex, disposals, capital contributions, the immediate expensing of capex and capitalised provision movements for the year.

Collectively, these updates result in an opening RAB value of $8,171.7 million real, 2023-24), a $32 million increase (0.4%) from the AER's draft decision value. This increase is driven by higher than forecast capex in FY23 due to the acceleration of key augex projects and unit cost increases arising from the global economic downturn. It also reflects higher than forecast expenditure in ICT related capex which is short-lived.

This revised value also includes an update to our opening asset value for the newly introduced lease asset classes. In particular, the long-term asset class has been updated to reflect a change in our leasing agreement for our new Parramatta Head Office. At the time of our January 2023 Proposal, it was anticipated that the lessor would provide a discount on the lease payments over the life of the lease which was reflected in the capitalised present value of the future lease payments. Since our Proposal, we have instead received an upfront payment from the lessor to cover the capex associated with fitting out and upgrading the new office space. This has resulted in a reduction to our FY23 capex

[18] AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023

but an equivalent increase in the opening asset value for long-term leases, i.e., the change is revenue neutral.

Return of capital (Depreciation)

The AER's draft decision accepted our proposed straight-line depreciation method, year-by-year tracking approach and standard asset lives and updated our proposed allowance based on the latest forecast of inflation.

We accept the AER's draft decision and have applied the same placeholder estimate of inflation. We have updated the AER's draft decision for the revised opening RAB value as detailed in the above section. Our revised depreciation allowance is $1,100.3 million (real, 2023-24) or 5.5% higher than the AER's draft decision. As noted above, this is driven by the higher than forecast capex in FY23, particularly within the short-lived ICT asset class. We expect further changes in the AER's final decision for the latest inflation forecast.

Return on capital

The AER's draft decision updated our Proposal for the final 2022 RORI which was released in February 2023. Ordinarily, the final RORI would have been published prior to our Proposal but there was a delay in its release. As a result, we applied the prevailing RORI at the time of our Proposal, the 2018 RORI. The adoption of the 2022 RORI has resulted in changes to our Proposal along with market movements in observable parameters.

We adopt the AER's draft decision placeholder WACC estimate noting it will be updated at the time of the AER's final decision. Our revised return on capital allowance is $2,366.1 million (real, 2023-24) or 0.2% higher than the AER's draft decision. As above, this reflects the updates to our RAB for actual FY23 expenditure.

We also note the AER's acceptance of our proposed averaging periods for the cost of debt and risk-free rate.

Regulatory inflation

The AER's draft decision included an expected inflation estimate of 2.80% as per the approach outlined in its final position paper from the 2020 Inflation Review. This estimate relies on the RBA's August 2023 Statement on Monetary Policy, specifically the June 2025 estimate, before applying a linear trend to the midpoint of the RBA's target band of inflation over the remaining years.

We adopt this placeholder estimate in our Revised Proposal noting it will be updated as part of the AER's final decision. At that time (April 2024) the RBA's February Statement on Monetary Policy will be available and include an estimate up until 2025 calendar year end (December) for use.

Corporate income tax

The AER's draft decision updated our January 2023 Proposal for the final 2022 RORI's estimate of imputation credits (gamma), the opening RAB value and estimate of inflation. Collectively, these amendments resulted in changes to our forecast corporate income tax. We accept the AER's methodology and have updated the draft decision for the impacts to further changes to our opening RAB value in this Revised Proposal. Our revised corporate income tax proposal is $98.9 million (real, 2023-24) or 4.9% higher than the AER's draft decision resulting from the increased depreciation allowance.

Operating expenditure (Opex)

The AER's draft decision accepted our proposed opex allowance of $1,497.6 million (real, 2023-24) as it fell within the AER's substitute estimate. We accept the AER's methodology and have updated it for the latest available information and benchmarks. Our revised proposed opex allowance is $1,496.6 million (real, 2023-24) with the updates summarised below.

Base year and category specific adjustments

We have updated our FY23 forecast opex for our actual performance of $247.5 million (real, 2023-24). At the time of our January 2023 Proposal, we forecast FY23 spend of $249.5 million (real, 2023-24). We have experienced significant and ongoing cost pressures with the high inflationary economic environment. However, we have largely been able to manage these challenges as reflected in our actual performance being near forecast.

We have also adjusted our base opex for changes in accounting standards, namely the capitalisation of leases and Software as a Service (SaaS) expensing. The AER accepted these adjustments in its draft decision and we have updated them in this Revised Proposal for FY23 performance. We have also adjusted our opex performance for EBSS and forecasting purposes for movements in provisions. The AER reverses provision movements so that customers only pay for provision amounts used within a given year. This is to ensure efficiency gains or losses realised within a period are rewarded or penalised under the EBSS and included in forecast opex.

In preparing this Revised Proposal we have identified an error in our reported provision movements for FY21 to FY23[19]. We have prepared our Revised Proposal on the basis of the corrected amounts contained in Attachment 0.27 this Revised Proposal. We note this update results in an immaterial variance to our Revised Proposal revenue requirement compared to the uncorrected figures of $2.8 million (real, 2023-24) over the 2024-29 period.

We have also adjusted our debt raising costs in accordance with our position to apply the AER's benchmark which has been updated from 8.19 basis points per annum (bppa) at the time of our January 2023 Proposal to 8.31 bppa as specified in the AER's draft decision[20]. We note this results in an immaterial change to our proposed debt raising costs of $0.2 million (real, 2023-24).

Step changes

The AER accepted our proposed step changes as our overall opex forecast fell within the AER's substitute estimate. However, the AER noted criticisms of the CER related step changes from EMCa's technical review. Notionally, the AER indicated a $2.0 million (real, 2023-24) reduction to our network visibility step change would have otherwise been made to our Proposal.

We will continue to refine our approach to estimating the appropriate level of network visibility and note our constrained approach to forecast step changes. With respect to the latter, the cost pressures we are facing have increased since our January 2023 Proposal. For instance, we have now quantified a step change of $9 million (real, 2023-24) associated with our SOCI Act compliance program costs for ongoing cyber-security costs. Other regulatory changes that could increase our costs beyond ordinary trends include the following non-exhaustive list:

- the new NSW Guaranteed Service Level (GSL) scheme that will come into effect 1 July 2025;
- AEMO has flagged that DNSPs may receive an allocation of costs in its next Participant fee structure period which commences 1 July 2026[21];
- new obligations for the provision of LV network and CER data to third parties in line with proposed Energy Security Board (ESB) reforms; and
- AER 'Game Changer' initiatives (yet to be finalised) will likely include some combination of industry funding and/or debt relief mechanisms.

Consistent with our commitment to providing a value for money service to customers, we have not sought to include these additional anticipated step changes in this Revised Proposal.

Trend factors

The AER's draft decision updated our proposed trend factors for its own consultant forecast of labour price growth. We accept the AER's draft decision methodology and have updated our expert consultant's forecast of labour price growth that is averaged with the AER's expert forecast. The revised expert forecast is provided in Attachment 0.26 to this Revised Proposal.

We have also updated the output weightings that are applied for the AER's final 2023 Annual Benchmarking Report (ABR) which marginally reduces our proposed opex.

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[19] Our provision accounts (as with all corporate overheads) are allocated between our SCS, ACS and unregulated activities on an annual basis. The percentage allocator for FY21 was not updated to reflect the changeover to SAP which enabled a more accurate allocator to be derived. The FY23 provision account closing balances reflect the correct allocators but also incorporate changes that should have occurred in earlier years (FY21 and FY22). This requires an amendment to template 3.2.3 of the Benchmarking RIN where provision movements are reported and table 8.2.4 of the Annual RIN that allocates these provision movements in 3.2.3 to RAB asset categories. All remaining capex and opex amounts reported in the RIN reflect the correct allocation percentages for FY21-FY23 and are unaffected by these changes.

[20] AER, Draft Decision – Endeavour Energy Electricity Distribution Determination 2024-to 2029 – Attachment 3 – Rate of Return, 28 September 2023, p.6.

[21] AEMO, Structure of Participant Fees for AEMO's NEM2025 Reform Program – Draft Report and Determination, June 2023, pp. 23-24.

Capital expenditure (Capex)

The AER's draft decision accepted our proposed capex allowance of $1,850.9 million (real, 2023-24) for the 2024-29 period.

We accept the AER's draft decision for the total capex allowance and provide some additional detail below in response to the AER's draft decision.

Capex by category

Typically, our Revised Proposal would update our capex proposal for the latest available forecasts and information and in response to issues identified by the AER. On the former, the external environment and trends that shaped our initial proposal remain. Our customers continue to make clear their preference for Endeavour Energy to improve network resilience and support an accelerated energy transition while maintaining a safe, reliable and affordable service.

In Chapter 2, we outlined developments in market conditions and policy reforms that highlight the growing challenge of striking the right balance in meeting customers' preferences. In particular, our forecast augex needs are facing significant pressure in the wake of increasing market unit costs and the following developments:

- the NSW Labor Government has increased the focus on housing delivery announcing accelerated development plans for Greater Macarthur;
- Wollondilly Shire Council is considering additional rezoning of lands outside the boundary of Greater Macarthur to support jobs growth; and
- Establishment of foundational infrastructure assets in several growth projects will likely be required sooner than originally anticipated.

In our January 2023 Proposal we noted our augex proposal of $412 million (real, 2023-24) was constrained from a portfolio of $550 million (real, 2023-24) of required investment for the 2024-29 period. The overall protfolio is now in excess of $650 million (real, 2023-24) given the economic challenges and accelerating development activity. However, as noted previously, we remain committed to our constrained expenditure proposal in providing a value for money service to customers during a cost-of-living crisis, and will re-prioritise our capex within the period to respond as required, consistent with the AER's position that its decision does not approve or require a DNSP to carry out individual projects or programs[22].

This re-prioritisation may include funding originally set aside for the Innovation Fund in our January 2023 Proposal, given the AER's draft decision not to expressly approve it.

We consider it is reasonable and necessary for DNSPs to invest in R&D to promote efficiency in the future (i.e., dynamic efficiency), and note that customers and stakeholders were highly supportive of the Innovation Fund as an important tool in discovering better ways of doing things, improving transparency in innovation and supporting the energy transition. We therefore remain committed to establishing something akin to the Innovation Fund for the 2024-29 period and to consult with our customers and stakeholders on innovative trials and projects. This will be funded within the AER's overall capex allowance via offsetting efficiencies and/or re-prioritisation within the 2024-29 period.

Amendment to the NEO to recognise emissions reduction

The most significant change since our January 2023 Proposal has been the inclusion of emissions reduction in the NEO. Beyond emissions reductions there are other environmental benefits our customers and stakeholders expect us to consider as well such as light, air, soil and noise pollution, waste reduction, resource conservation and protecting biodiversity. These expectations form part of the broader trend towards a circular economy which promotes designing out waste and pollution, keeping materials in use and regenerating natural systems. Our sustainability strategy adopts a circular economy view in line with community expectations, but we note the amended NEO takes a narrower view of focussing on emissions reduction alone.

[22] AER, Draft Decision – Endeavour Energy Electricity Distribution Determination 2024 to 2029 – Attachment 5 – Capital Expenditure, 28 September 2023, p. 9

In support of the NEO change the AER has released a guidance note and the AEMC has published the first targets statement. The latter includes a listing of jurisdictional emissions reductions targets, for NSW this includes a 50% reduction below 2005 levels by 2030 and Net Zero by 2050.

In the limited time available in preparing this Revised Proposal it is difficult to fully assess and scope the level of efficient investment required to support these targets. Actions we could take to reduce greenhouse gas emissions include:

EV Fleet transition;	**Solar PV and energy efficiency measures** for Endeavour Energy owned property;	**Network augmentations** and investment to enable EV uptake, CER and electrification;
Reducing line losses (e.g., low loss cable and line designs);	**Investing in new technologies and materials** in network upgrades and maintenance that are more durable and/or resource-efficient;	**Reduce or eliminate the use of SF6,** a potent greenhouse gas, in transformer and switchgear replacement programs and new installations;
Advance distribution management systems (ADMS) and Dynamic Operating Envelopes (DOE) to reduce peak demand and enable increased CER hosting;	**Prevent outages** or the use of diesel generators in emergency responses; and	**Network or community batteries** to reduce peak demand and enable increased CER hosting.

Although not an exhaustive list, this illustrates the breadth of considerations required to operate and maintain the network in a manner that supports the achievement of emissions reductions targets. To determine an efficient level of investment we must quantify emissions, the potential reductions associated with an investment and develop a value of carbon. In turn, these inputs allow us to derive a VER that can be used to quantify the benefits of emissions reductions initiatives and assess these against the costs of doing so.

There are a wide variety of approaches to valuing carbon across the energy industry and more broadly. We have observed values fluctuating between $30/tCO2 to $130/t/CO2 noting that same businesses escalate these prices over the horizon being considered. The European Union (EU) used a much higher carbon price that peaked at €100/tCO2 in February 2023 with Bloomberg forecasting the averaging price to reach €149/tCO2 by the end of the decade[23].

We have relied on a placeholder estimate of $50/tCO2 in our investment framework based on advice from KPMG which relied on Australian Carbon Credit Units (ACCU) Carbon Prices over the last 12-months which is considered a conservative estimate.

As previously noted, our customers and stakeholders are becoming increasingly concerned with energy affordability while also having a keen interest in reducing carbon emissions. At this stage, we remain of the view that our January 2023 Proposal struck the right balance in meeting customers' competing priorities. For this reason, we have decided not to increase our expenditure allowances in this Revised Proposal in response to the amended NEO. We will continue our ongoing engagement with the AER in relation to this important topic, update our value framework to include a VER and re-prioritise our projects within the overall allowance accordingly over the course of the 2024-29 period.

Responding to EMCa feedback

As noted in the AER's draft decision, 15% of our proposed capex was subject to more detailed assessment by the AER and its technical consultant EMCa. This involved a review of our non-

[23] BloomgbergNEF, EU ETS Market Outlook 2H 2023: Cleared for the Ascent [website], https://about.bnef.com/blog/eu-ets-market-outlook-2h-2023-cleared-for-the-ascent/, accessed (10 November 2023).

recurrent ICT expenditure, cyber-security, network resilience and CER enablement spend. These categories were subject to detailed review for all 6 DNSPs submitting 2024-29 proposals.

Although the AER and EMCa's review identified several areas for improvement in our approach to establishing and justifying investment requirements for these categories, reductions were not applied to our proposal as the AER's substitute estimates were similar to our proposed spend for these categories.

The AER recognised our significant improvement in our asset management approach following the 2019-24 determination process. This reflected a broad and concerted organisational effort over the last few years to respond to the criticisms made by the AER and EMCa at the time of the 2019-24 determination. We will again take this determination process as an opportunity to consider our asset management strategies and approach to identify further opportunities for improvement.

We also wish to clarify an apparent error identified with our CER enablement modelling. Specifically, EMCa's review found an error in the model's representation of NPVs and the approach taken to discounting values, concluding[24]:

> *Endeavour's 'NPV' results are as shown in Figure 3.9. However, due to the modelling flaws referred to above we conclude that the CBA model does not contain any valid representation of the annual benefits or net benefits in the next regulatory period, nor of the NPV of the proposed DER program nor of any element of that proposed program.*

EMCa's review was otherwise generally supportive of our assessment approach and the inputs used. If this issue had been raised with Endeavour Energy prior to the preparation of the report, a corrected model could have been provided. To clarify, the model incorrectly labels the forecast costs and benefits as nominal dollars when it has instead been prepared in the dollars of the day (i.e., real; 2022-23 terms). As a result, the summary worksheets simply need to convert the analysis worksheets from FY23 terms to FY24 terms and to disregard the 'NPV' calculation. Given the error applies equally to both the costs and benefits contained in the model it will not materially impact the outcomes or conclusions it supports and therefore should not be disregarded.

EMCa also raise concerns with the approach taken to determining the timing of distribution substation augmentation[25]:

> *….the model incorporates flawed logic on the optimum timing to undertake works that are determined on the basis of their economic value. Specifically, the first year in which a positive NPV is achieved is not necessarily the optimum (from an economic perspective) and it is typically the case that the NPV is higher if the investment is deferred.*

In the context of CER enablement spend, we question whether this approach to investment timing is appropriate. For repex, waiting for the optimum NPV is appropriate but this is not necessarily the case for CER enablement which is more akin to augex in a greenfield area. In this case, the NPV will theoretically increase into perpetuity as the level of CER curtailment reaches a maximum for all existing and new customers in a given area. We consider it appropriate to exercise discretion in deciding when to intervene to alleviate CER curtailment and believe our approach is consistent with the feedback we have heard from our customers and stakeholders who have expressed a strong preference for Endeavour Energy to enable their take-up and deployment of CER to better manage and reduce their energy costs and carbon footprint.

That is also not to say that our approach unduly favours or prioritises addressing constraints experienced by CER customers. In fact, our proposal results in an increasing level of curtailment per customer which is to be expected as the take-up of CER increases rapidly. To strike the appropriate balance, we have proposed to only intervene where it is efficient to do so by applying the AER's Customer Export Curtailment Value (CECV) and DER Integration Expenditure Guidance Note. As a result, rather than overstate required CER enablement spend, our Proposal likely understates it. This is evidenced by several conservative input assumptions we have applied and developments since the lodgement of our January 2023 Proposal, including:

- **Updated AEMO Inputs, Assumptions and Scenarios (IASR):** The CER forecasts and load profiles used in our modelling were developed from the 2021 version of the AEMO IASR. The 2023 report was released by AEMO in July 2023 with material changes to key inputs. These

[24] AER – Endeavour Energy 2024-29 – Draft Decision – EMCa report to AER on Endeavour Energy 24-29 DER and ICT, August 2023, p. 29
[25] AER – Endeavour Energy 2024-29 – Draft Decision – EMCa report to AER on Endeavour Energy 24-29 DER and ICT, August 2023, p. 30

changes (for the step change scenario specifically) include a 20% increase in rooftop PV forecasts in conjunction with a 15% decrease in embedded energy storage forecasts (behind the meter batteries). The assumptions used in EV charging behaviour were also adjusted resulting in a significantly lower demand profile. These adjustments all increase the levels of curtailment on the network and therefore the efficient level of CER enablement spend.

- **Network Model Improvements:** The model is an ongoing and improving tool used in the business with workflow and accuracy improvements continuously added. Since the January 2023 Proposal we have identified that our ADMS system was incorrectly defaulting customer service main conductors for over 50% of customers. This results in the modelling underestimating voltage rise and curtailment due to unrealistically low impedance values. This has now been corrected and incorporated into the latest model.
- **Updated CECV methodology:** We applied the AER's CECV estimates in developing our Proposal rather than averaging it with our expert consultants estimates under the advice of the RRG. This resulted in lower values being applied. In June 2023, the AER published new, higher CECVs based on AEMO's updated inputs and assumptions. The annual average values are generally higher in later years driven by higher Battery Energy Storage System (BESS) cycling costs and pumped hydro entering post 20303 and higher during peak periods in earlier years reflecting higher gas prices.
- **Value of Emissions (VER):** in developing our Proposal we did not include a VER as agreed with the RRG. Since our Proposal was lodged the NEO has been amended to include the achievement of jurisdictional and Federal emissions reductions targets. We will apply a VER estimate in re-prioritising our expenditure over the course of the period which will likely result in additional CER enablement spend being justified (i.e., efficient and prudent). We note the AER intends to publish a VER estimate in late November 2023, in the interim we have obtained an estimate from KPMG to factor into our decision-making processes.

Given this, we remain of the view that our CER enablement forecast understates rather than overstates the efficient level of expenditure as suggested by EMCa. We will continue to monitor key assumptions and refine our modelling to re-prioritise our capex over the course of the period to enable an efficient level of CER hosting.

Revised capex proposal

Our revised capex proposal accepts the AER's draft decision and for completeness is set out in the table below. Refer to section 4.3 for further detail on the addition of Type 5 & 6 metering capex to SCS capex.

Table 4-2 Forecast capital expenditure over the FY25-FY29 regulatory period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Main SCS Capex	**436.8**	**406.8**	**365.9**	**354.2**	**318.5**	**1,882.2**
Disposals	*6.3*	*6.3*	*6.3*	*6.3*	*6.3*	*31.3*
Main SCS Net Capex	**430.6**	**400.5**	**359.6**	**347.9**	**312.2**	**1,850.9**
Metering SCS Net Capex	0.5	0.4	0.4	0.4	0.4	2.0
Total SCS Net Capex	**431.1**	**400.9**	**360.0**	**348.3**	**312.6**	**1,852.9**

Revenue adjustments

Calculation of incentive scheme carryover amounts

We accept the AER's methodology for determining the incentive scheme carryover amounts for the EBSS and CESS respectively. We have updated the AER's draft decision for FY23 actual performance.

We note that as a result of higher than forecast capex spend for FY23, coupled with lower than forecast capital contributions for the year, the CESS benefit has reduced from a $12.6 million (real, 2023-24) benefit to a $4.0 million (real, 2023-24) penalty. As noted in Chapter 2, the global economic downturn has resulted in significant material cost pressures within the current period that we are managing. Overall, our net capital expenditure remains below the allowance for the current period.

Our revised EBSS carryover amount is $123.4 million (real, 2023-24) which is lower than the AER's draft decision of $131.2 million (real, 2023-24). This change is driven by updating for FY23 actual performance and the correction to our provision movements in earlier years.

Shared Asset Revenue adjustment

The AER's draft decision accepted our proposed revenue adjustment for shared asset revenue proposed in accordance with the Shared Asset Guideline. At the time of our January 2023 Proposal, our forecast revenue from the shared use of distribution assets exceeded the materiality threshold (1% of our SCS Annual Revenue Requirement) triggering a 10% sharing of forecast shared asset revenue.

We note however, that our forecast only marginally exceeded the allowance based on our proposed smoothed revenue profile. Based on our calculations using the AER's draft decision, we believe the forecast of shared asset revenue fell below the draft annual revenue requirement in year 2 of the 2024-29 period. As this remains the case in this Revised Proposal, we have amended our Proposal to remove the shared asset revenue adjustment for year 2 of the period in accordance with the requirements of the AER's Shared Asset Revenue Guideline.

We note that further increases in our final revenue allowance (e.g., for inflation or WACC updates) could result in other years falling below the materiality threshold, which may necessitate further amendment to the shared asset revenue adjustments applied.

Demand Management Innovation Allowance Mechanism

We accept the AER's methodology for determining the DMIAM revenue adjustment and have updated it to reflect the updated revenue requirement in this Revised Proposal. Our revised DMIAM is $5.1 million (real, 2023-24).

Revised Revenue Requirements

Smoothed revenue requirements and x-factors

As a result of the updates outlined in this Proposal, our Revised Proposal smoothed revenue requirement is $5,201.8 million (real, 2023-24) for the 2024-29 period (excluding metering). This represents an 1.0% increase compared to the AER's draft decision and is primarily driven by the higher than forecast capex for FY23 (information that was not available at the time of our January 2023 Proposal).

The revenue impact of the changes made to the AER's draft decision are relatively low, and we consider these to be uncontroversial amendments. We also acknowledge that additional updates will be required to the AER's final decision that will result in further refinement of the forecast revenue allowance. Our revised revenue allowance and x-factors are provided in the PTRM, Attachment 0.07 to this Revised Proposal and set out in the table below.

Table 4-3 Main SCS revised unsmoothed and smoothed annual revenue requirement for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed revenue requirement	1,121.2	1,041.0	1,048.1	997.7	982.1	**5,190.2**
Revenue X-Factors*	-8.80%	-8.80%	1.40%	1.40%	1.40%	
Smoothed revenue requirement	988.6	1,075.6	1.060.6	1,045.8	1,031.2	**5,201.8**

* A negative revenue X-factor denotes a real revenue increase.

We note that in smoothing the draft decision the AER targeted a maximum final difference of ±3% resulting in revenue increases in the first two years of the period followed by reductions over the remaining three. We have sought to adopt a similar smoothing profile in this Revised Proposal. In doing so we have targeted a final year difference within +5% as this reduces the increase required in the first two years of the period materially (by 0.77% in each year). This results in lower increases in the first two years compared to the AER's draft decision despite the 1.0% increase in our revised revenue requirement.

Under the Rules the AER has discretion as to what it considers to be a "reasonable" final year difference. We note in the draft decision for Ausgrid, a +5% final year difference was targeted for revenue smoothing to reduce the real revenue increases required over the first three years of the 2024-29 period (by 0.3% in each year)[26]. We have tested multiple smoothing approaches and consider our Revised Proposal best balances revenue stability and energy affordability.

This section sets out our Revised Proposal SCS revenue requirement and indicative bill impacts exclusive of metering for comparison purposes with the AER's draft decision and our January 2023 Proposal. However, as noted elsewhere in this proposal, we propose that Type 5 & 6 Metering Services are re-classified as SCS for the 2024-29 period. For completeness we set out our total SCS revenue requirement for the 2024-29 period in the table below. That is, inclusive of "main" SCS (above) and metering SCS (set out in section 4.3). We note the x-factors for these components of SCS remain separate with the metering SCS x-factors set out in section 4.3.

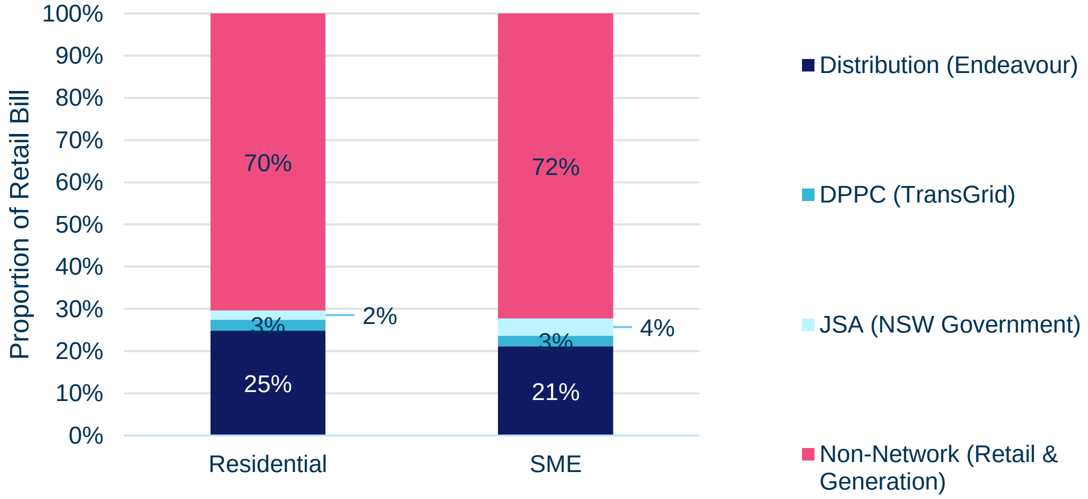
Table 4-4 Total SCS revised unsmoothed annual revenue requirement for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed Main SCS revenue requirement	1,121.2	1,041.0	1,048.1	997.7	982.1	**5,190.2**
Unsmoothed Metering SCS revenue requirement	20.7	19.6	17.7	15.6	12.5	**86.1**
Total SCS unsmoothed revenue requirement	1,141.9	1,060.6	1,065.8	1,013.3	994.6	**5,276.2**

Indicative charges and bill impacts

Our contribution to the average electricity bill is 25% and 21% for residential and small business customers respectively.

Figure 4-2 Breakdown of component parts of average electricity bill



We have worked hard over the previous and current regulatory periods to keep downward pressure on our contribution to electricity prices. By focusing on making broad and targeted improvements to make our business more efficient, network charges for the average residential customer's bill have fallen by 35.7% over the last 10 years and by 27.9% for small business customers.

Indicative DUOS prices for 2024-29 based on our revised bundled revenue and our forecast of energy volumes are provided in the table below.

[26] AER, Draft Decision Attachment 1 – Annual revenue requirement – Ausgrid 2024-29 Distribution revenue proposal, 28 September 2023, p. 12

Table 4-5 Indicative average DUOS for FY23-FY29 (exclusive of metering)

$; Real FY24	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Residential customer consuming 4.9MWh p.a.	521.1	496.7	536.2	578.5	553.9	533.9	514.2
Small business customer consuming 10MWh p.a.	922.7	873.3	942.8	1,017.0	973.9	938.6	904.0

We note these increases (relative to FY24) are driven almost entirely by factors outside of our control. Namely, the economic downturn has materially increased the cost of capital that is derived by applying the RORI.

We also note that the prices outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF) and NSW Electricity Infrastructure Roadmap. These components are also outside our control.

We have constrained all factors wholly within our control as much as reasonably practicable to limit the impacts of the WACC and expected increases in other components of electricity bills.

The prices outlined above are indicative only and will be updated in our Pricing Proposal for each year of the 2024-29 period to reflect:

- updated energy consumption forecasts;
- actual CPI;
- updated cost of debt;
- incentive scheme performance; and
- any changes in the relative portion of revenues recovered from each tariff and tariff component.

4.2.5. Revised Tariff Structure Statement

The AER's draft decision accepted the majority of our draft Tariff Structure Statement (TSS), while requesting we consider providing the following:

- Supporting information to shorten the residential and small business transition period to cost reflective tariffs from 24 months to 12 months;
- Worked examples of the export charge and reward tariff and an explanation of how Green Hydrogen producers will be priced under the NSW Government Scheme; and
- Further consideration of uncontrolled EV charging and whether specific tariff options are required to help to manage this.

The AER did not approve our embedded network tariff and requested further supporting analysis.

We accept the AER's draft decision and have provided the requested supporting information and worked examples. For EV charging, we consider that our proposed tariff options (including controlled load tariffs) are appropriate, however, we will consider trial tariff options to further explore EV appropriate tariff options over the regulatory control period.

We have revised the proposed embedded network tariff to recognise the potential for network cost savings from the connection of embedded networks.

Further detail of our proposed tariff structures is provided in our revised Tariff Structure Statement (Attachment 0.05) and revised Tariff Structure Explanatory Statements (Attachment 0.06).

4.2.6. Other key constituent decisions

Dual Function Assets

As part of the draft decision, the AER confirmed its decision from previous determinations that distribution pricing would continue to apply to our dual function assets. This was due to our dual function assets being an immaterial proportion of our overall regulated asset base. Further, these assets are dedicated to our distribution network meaning that separately pricing them as transmission assets would not have any material impact on our distribution prices. We accept this decision.

Negotiating Framework

We agree with the AER that none of the services we provide are suited to being classified as negotiated distribution services. Nevertheless, we provided a negotiating framework outlining the procedures we would otherwise follow in negotiating the terms and conditions of any prospective services with other parties for completeness as part of our January 2023 Proposal[27]. The AER accepted our proposed negotiating framework in the draft decision. We accept this decision.

Connection Policy

The AER's draft decision did not accept our Connection Policy as initially proposed. Following the lodgement of our January 2023 Proposal the AER suggested a number of amendments to bring the policy into greater alignment with recent changes to the NER regarding export limits. We accepted these proposed changes which the AER's draft decision reflects. We therefore accept the AER's draft decision. Attachment 0.04 to this Revised Proposal is a designed version of the policy the reflects the AER's draft decision.

Nominated Pass-through events

The AER's draft decision accepted the four pass-through events we nominated in our January 2023 Proposal for the 2024-29 period, these being:

- Insurance cap event;
- Insurer's credit risk event;
- Natural disaster event; and
- Terrorism event.

The AER did not however, accept our proposed amendments to the definition of a natural disaster event. We proposed amendments to this event to clarify that a declaration by a State or Federal Government is a relevant consideration in determining whether a natural disaster event has occurred. We also sought to clarify that a natural disaster could be an event, or series of related events given our experience with the 2019-20 Bushfires. In rejecting these proposed amendments the AER considers the existing definition provides sufficient scope for the AER to have regard to these factors when assessing a natural disaster cost pass through. We accept the AER's draft decision.

We also note our January 2023 Proposal suggested the AER re-consider the name and definition of a terrorism event[28]:

> *In our view, the 'terrorism' event remains a valid and enduring threat, but it is also risks becoming antiquated and narrow in its language and focus. By its current definition, the event refers to acts done for, or in connection with, political, religious, ideological or similar motivations. This could be applied in a limited away to exclude other acts of aggression or malice, such as, cyber-attacks done for ransom or for the sake of causing disruption alone rather than to stoke fear in the community to achieve an ideological end.*
>
> *There may be merit in changing the 'Terrorism' event name itself to 'Acts of aggression' and/or adjusting the definition to focus on intentional and malicious acts of aggression rather than a subset of them (terrorist attacks). Alternatively, the AER could re-confirm and/or clarify how the event as currently defined remains suitable in an evolving geopolitical environment. We consider acts of war, terrorism and/or cyber-attacks to be so similar in the outcomes they*

[27] NER 6.7.5 (a)(b)(c)
[28] Endeavour Energy, Regulatory Proposal 2024-29, January 2023, p. 95

> *impose on customers that they should be captured collectively by this nominated pass-through event.*

Similar to the above, the existing event definition may provide the AER sufficient flexibility by way of 'similar motivations' in the definition to have regard to other acts of aggression such as war or cyber-attacks in applying the terrorism event. However, we recommend the AER clarify its position on this matter in making its final decision.

Contingent Projects

We did not propose any contingent projects in our January 2023 Proposal and confirm that this remains the case for this Revised Proposal.

4.3. Metering Services

4.3.1. Overview

As discussed in section 4.2, there has been a material change in circumstances since the lodgement of our January 2023 Proposal with respect to Type 5 & 6 (Legacy) Metering Services. The AEMC's final metering framework review sets out a number of reforms that will be implemented via a rule change process over the coming months. These reforms aim to establish a process for accelerating the retirement of existing legacy meters and framework for the sharing of basic PQD.

We support these reforms and consider the contestable metering framework has failed to transition customers to smart metering in a timely manner or unlock the benefits associated with it. However, the reforms also bring into question whether the existing regulatory approach for legacy metering remains suitable. As discussed in Attachment 0.03, we do not consider an ACS classification will best promote the long-term interests of customers under an accelerated transition.

As the legacy metering customer base progresses towards a small number of customers a significant equity issue arises. This smaller customer base could face exponentially increasing prices to recover the outstanding MAB and the ongoing operating costs which do not reduce 1:1 with reductions in the customer base.

In addition, the AEMC notes that vulnerable customers face higher risks of being excluded from the roll-out because[29]:

> *……they are more likely to be in positions where decisions making regarding remediation is out of their control and face higher financial hurdles for undertaking remediation. Vulnerable energy customers can overlap with the more socio-economically disadvantaged parts of the community. Customers who don't own their own homes or live in social or public housing are more likely to fall into the vulnerable energy customers category. In many cases, such customers may not have the required authority to make decisions regarding undertaking remediation. Electrical installations generally form part of the infrastructure that the building owner or operator is required to provide and maintain. This would leave vulnerable customers in a position where they are less able to benefit from the smart metering upgrades.*

The AEMC's reforms to accelerate smart meter uptake will likely exacerbate this issue and therefore it is appropriate to consider the reclassification of metering services for 2024-29.

The issue of socialising the costs of this transition towards smart metering was discussed with our RRG. This engagement session included a proposal to accelerate the recovery of the MAB and a comparison of various outcomes under the current ACS classification against a prospective change to a SCS classification (and revenue cap form of control) which we indicated was our preferred option. Some of the key observations included:

- Socialising metering costs evenly across all SCS customers results in a lower cost per customer;
- Non-Type 5 & 6 customers would see an increase in overall cost, noting smart metering costs are likely socialised across Type 5 & 6 customers by retailers currently; and
- As the MAB recovery is accelerated and metering opex reduced for churn, the SCS metering price impact reduces materially over the 2024-29 period.

Our RRG acknowledged that a reclassification would require transitioned customers to share in the costs of metering assets/services not provided to them. However, on balance they indicated this concern is outweighed by the price risk to the remaining customers and therefore supported socialising metering costs across all customers through a reclassification to a SCS.

With regard to the proposal to accelerate recovery of the MAB, our RRG noted that whilst this would bring forward costs, the AEMC reforms to accelerate the replacement of legacy meters would reduce the 'double payment' equity issue. Consequently, our RRG supported the proposal to accelerate the depreciation of the MAB in parallel with the accelerated replacement of legacy metering over the next few years.

[29] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.96

Section 4.3.3 sets out the pricing outcomes of an SCS classification relative to the AER's draft decision.

We set out our Revised Proposal with respect to key input assumptions and the revenue outcomes below.

4.3.2. Metering Building Block assumptions

Return on and of capital

We accept the AER's draft decision with respect to:

- the opening MAB value of $13.9 million (real, 2023-24);
- the decision to accelerate the recovery of the MAB over the 2024-29 period;
- the capex, as proposed, for the period of $2.0 million (real, 2023-24), the recovery of which will also be accelerated over the period; and
- the AER's placeholder WACC, as applied to the SCS PTRM, calculated in accordance with the 2022 RORI and to be updated at the time of the AER's final decision

Operating expenditure (opex)

Base year opex and adjustments

The AER applies a base-step-trend method to deriving the legacy metering opex allowance similar to the approach taken for SCS opex. We accept this methodology and have updated our base year opex for actual FY23 expenditure of $18.0 million (real, 2023-24). This is $3.9 million (real, 2023-24) lower than our proposed base year opex set out in our January 2023 Proposal.

Step changes

We propose the following step changes to reflect the change in efficient costs we expect to incur as a direct result of complying with new obligations set out in the AEMC's metering framework review final report.

Table 4-6 Metering step changes for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Meter Testing	-	(0.3)	(0.3)	(0.3)	(0.3)	**(1.0)**
LMRP Management	0.6	0.6	0.6	0.6	0.6	**2.8**

Meter Testing

The AEMC recommended that DNSPs be exempt from requirements to periodically inspect and test Type 5 & 6 meters during the acceleration period (FY26-FY30).

We therefore propose to incorporate the avoided cost from this pause on our meter testing obligations through a negative step change adjustment from FY26. The step change amount is derived from the meter testing expenditure incurred in the FY23 base year.

Legacy Meter Retirement Plan

A key component of the AEMC's final metering review report is introducing an obligation for DNSPs to develop LMRPs that schedule clusters of legacy meters to be retired and replaced in each year of the acceleration period. In developing LMRPs, DNSPs will be required to:

- provide retailers with detailed information about the sites at which legacy meters need to be replaced to the extent that this information is available;
- consult with retailers, metering parties and other affected stakeholders and address their feedback; and
- submit plans that are developed in accordance with the LMRP objective, guiding principles and minimum content requirements for AER approval.

Satisfying these requirements is a substantial task that will require additional resources dedicated to developing the LMRP. We will conduct an extensive engagement process to develop our LMRP and then shift towards a variety of activities to facilitate compliance with the LMRP. We expect to liaise closely and frequently with retailers and meter installers and provide assistance and advice. In addition to this, activities we will undertake for the duration of the acceleration period include, but are not limited to:

- assessing the eligibility of applications from retailers to amend the LMRP and any associated pre-lodgement activities with retailers;
- where applications meet the materiality threshold for amendment, undertaking consultation on the proposed amendments prior to submitting the revised LMRP to the AER for approval;
- collating and distributing to retailers and metering parties any relevant site-specific information held in our systems and notifying them of any changes;
- planning and scheduling work to facilitate meter replacements under the one-in-all-in process with a focus on minimising the incidence of subsequent group isolations due to a party not attending the initial planned outage;[30]
- splitting the charge for distributor planned interruptions for shared fuse/multi-occupancy sites so that retailers are accurately charged on a pro-rata basis;
- managing customer LMRP enquiries and resolution of complaints; and
- contributing to the industry-led communications strategy that aims to improve public awareness and social licence of the LMRPs and publish tailored information material for our customers that is consistent with this strategy.

To perform these tasks, we have determined that the following additional LMRP-dedicated resources will be required:

- 1 x LMRP Project Manager @ $200,000 per FTE;
- 1 x LMRP Analyst @ $170,000 per FTE; and
- 2 x LMRP Support Officers @ $90,000 per FTE.

These salaries are based on the 2023-24 Hays Salary Guide and have been used to derive a positive step change from FY25.

Site Remediation

Defects in the customer's electrical installations can often prevent metering installations and will limit the level of smart meter uptake that could be successfully achieved under the acceleration program. Whilst the rates of major site defects vary across jurisdictions, the AEMC expects major site defects to be encountered in approximately 10% of sites[31].

Customers will continue to face costs in undertaking the remediation work necessary to enable metering upgrades. However, this will result in an inequitable and non-uniform deployment of smart meters as some customers will receive access to smart meters and their associated benefits, while others will not, depending on the state of their electrical installation and their ability to afford and/or conduct site remediation.

To mitigate this, the AEMC has recommended governments consider arrangements, including financial support for customers to undertake site remediation. They also recommended jurisdictions to consider reviewing their legislative arrangements that drive the need for remediation, including amendments to Service and Installation Rules which specifies metering installation requirements in NSW.

As discussed in section 2.3, the NSW Government has signalled its commitment to developing a CER Strategy in response to the Check Up Report recommendation for setting targets for the uptake of technologies such as smart meters. Although the NSW Government is yet to action any of the

[30] This would typically involve administrative activities beyond what is currently required to prepare a group isolation and not factored into the existing ANS fees.
[31] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.89

Report's recommendations, we expect a pathway to resolve site remediation issue will feature in the strategy.

Given the AEMC's recommendation and no current guidance from the NSW Government on new arrangements to address defects, we have not proposed to include any costs to remediate sites. However, if there is a change in regulatory responsibility that means we must contribute to site remediation services we would seek cost recovery.

If the NSW Government provides clarity on this regulatory change prior to the AER's final decision, we consider it would constitute a material change in circumstances that would warrant service classification changes and the opportunity to revise our forecast. If this occurs subsequent to the AER's final decision we intend to consider a pass-through proposal subject to the materiality threshold.

Trend factors

Proportion of variable costs

In relation to the trending of metering opex, we support the AER's rationale for amending the metering opex model to distinguish the portion of variable costs (assumed to be 65%) from fixed costs and ongoing application of the AER's (dis)economies of scale factor of 60.30%.

Legacy meter volumes and churn rates

The AER's proposed approach includes an adjustment mechanism to vary opex based on actual churn rates. We support this approach as there is significant uncertainty around the churn rates that will be achieved which creates a risk of DNSPs earning windfall gains or losses over 2024-29 period. An adjustment mechanism will ensure that customers ultimately only fund the benchmark opex associated with actual metering stock.

However, we still consider it important to include the most accurate forecast available in the determination to reduce the potential for revenue volatility within the period to the greatest extent possible. We are therefore not supportive of the assumption in the AER's draft decision that legacy metering will be fully churned by 2030, based on the AEMC's targets.

We also note the opening value was based on a continuation of BAU churn rates before a steep increase in churn rates over the 2025-30 acceleration period. Although we agree that recent churn rates should inform FY24 and FY25 legacy meter estimates, this assumption results in a reduction in meter churn volumes which is incongruent with our latest expectations.

While our FY23 performance is reflected in the AER's draft decision, over the first quarter of this financial year we have observed an increase in the number of churns occurring. Given this, we have updated our metering churn forecast in FY24 and FY25 to reflect a continuation of the increasing volume of meter retirements which have been observed since FY22. We consider this is more representative of the BAU trend than applying the actual rate of meters churned in FY23 in the following two years. This update to our BAU trend means that we expect to churn 12.1% of our meters in FY25 compared to 8.7% in the draft decision. This adjustment lowers our opening stock of legacy meters for the 2024-29 period which reduces our opex requirements.

Secondly, we propose to vary the stock of legacy meters at the end of 2024-29. Although the AEMC's recommendations target universal smart meter penetration by 2030, they recognise this may not be achievable in practice as metering parties could face barriers to installation such as defects in customers' electrical installations, difficulty in gaining access, and customer refusals[32]. Furthermore, the AEMC acknowledge that in other jurisdictions, where a coordinated smart meter rollout has been completed, some of the more challenging sites are completed after the originally set target. As such, the AEMC concludes[33]:

> *Overall, we expect approximately 10–15 per cent of sites will be higher cost or difficult to install smart meters at due to meter board remediation, site access and customer refusal issues. This estimate is based on evidence provided in submissions and industry discussions.*

[32] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.32
[33] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.

By way of illustration, in the case of the AMI rollout in Victoria, approximately 93% of the targeted replacements were achieved by the end of the rollout in December 2013[34]. Key reasons for the remaining 7% of sites not having a smart meter installed by this date include:

- There was no attempt to install a meter;
- The customer had actively refused the installation;
- Access issues such as locked gate or aggressive dog; and
- Other issues such as meter board defects or technical issues.

The rollout performance of each Victorian DNSPs is outlined in the table below[35]. It is noteworthy that DNSPs were assessed against a target of installing functioning AMI meters to at least 90% of prescribed customers. The Essential Services Commission Victoria (ESCV) rationale for setting the rollout target below 100% was to recognise there were common issues beyond the control of the distributors during the rollout period.

Table 4-7 Victorian DNSP AMI ESCV rollout performance

	Powercor	CitiPower	Jemena	United	AusNet
AMI Rollout Target (90%>)	94%	97%	90%	83%	58%

Significantly, the Victorian rollout was DNSP-led and unlike the AEMC's recommendations, did not rely on the cooperation and compliance of third-party retailers and metering parties to install meters. The more streamlined arrangements of the AMI rollout would suggest that the performance against the target outcomes achieved in Victoria may be difficult to replicate in other NEM jurisdictions.

Barriers to achieving 100% smart meter penetration by 2030 were also recently highlighted by several retailers in their submissions to the AEMC. For instance, Energy Australia considered there are issues with completing meter exchanges that are not initiated by the customer and provided data indicating that 22% of meter installations are unsuccessful at the first attempt predominantly due to isolation, access, site defect and customer consultation/contact[36]. Importantly, they state:

> *We envisage the accelerated roll-out will encounter similar percentages of unsuccessful meter installations, and that without developing a framework requiring remediation for the range of issues impeding an installation, universal uptake of metering is highly unlikely.*

Simply Energy considered sites with defects present the most significant barrier to the successful achievement of the AEMC's target[37]. Similarly, Red Energy and Lumo Energy list various considerations and unforeseen circumstances that would impede the rollout and highlight the AMI rollout which commenced in Victoria in 2006 is yet to achieve its universal smart meter target[38]. To this, we note that some Victorian DNSPs continue to have replacement meter programs in place to encourage smart meter uptake almost 10 years after the end of the AMI rollout.

In addition, the AEMC's final report notes that in an industry reference group meeting consisting of all relevant stakeholder groups, 40% of the participants did not believe a universal uptake of smart meters could be achieved by 2030[39].

In light of these barriers the AEMC state that the target of universal uptake will mean that every small customer either receives a metering upgrade ***or has an opportunity*** to have their meter upgraded by 2030[40]. It is therefore consistent with the AEMC's expectations and compliant with the (likely) Rules to forecast a level of meter churn that is not completed by 2030.

In consideration of the above, we believe is it prudent to estimate a portion of our legacy meter stock that will not be replaced by 2030 via the exemption framework (i.e., ignoring instances of non-compliance). We have adopted an estimate of 7% of meters will not be replaced by the end of the LMRP period in this Revised Proposal. This more optimistic forecast aligns with the outcomes observed in the Victorian AMI rollout, notwithstanding the generally less favourable arrangements for

[34] Victorian Auditor- General, Realising the Benefits of Smart Meters Report, September 2015, p. 17.
[35] Essential Services Commission, Compliance with AMI Regulatory Obligations at 31 December 2013 - Final Report, October 2014, p.12
[36] EnergyAustralia, Submission to the review of the regulatory framework for metering services draft report, 2 February 2023, p. 3.
[37] Simply Energy, Submission to the review of the regulatory framework for metering services draft report, 2 February 2023, p. 1
[38] Red and Lumo Energy, Submission to the review of the regulatory framework for metering services draft report, 2 February 2023, p. 2
[39] AEMC, Draft Report – Review of the regulatory framework for metering services, 3 November 2022, p.36
[40] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.30

a successful transition to smart metering in NSW. This includes our limited ability to directly partake in the rollout of the meters and influence compliance to the targets compared to the Victorian DNSPs.

Our estimate for FY30 delivers a legacy meter stock forecast in FY29 (231,556) that is 273,023 meters less than our January 2023 Proposal. Our revised meter churn forecasts, combined with the updated base year opex and proposed step changes results in a reduction in our opex requirements of $6.5 million (real, 2023-24) compared to the AER's draft decision. We note that the AER's adjustment mechanism will ensure that only benchmark efficient opex for actual metering volumes will ultimately be earned. Refer to Attachment 0.20 for our revised metering expenditure model.

4.3.3. Metering Revenue Requirements

As a result of the updates outlined in this proposal, our Revised Proposal smoothed metering revenue requirement is $86.5 million (real, 2023-24) for the 2024-29 period. This represents an 7.4% decrease compared to the AER's draft decision.

The revenue impact of the changes made to the AER's draft decision are relatively low, and we consider these to be uncontroversial amendments. We also acknowledge that additional updates will be required to the AER's final decision that will result in further refinement of the forecast revenue allowance.

The resulting revenue requirement and X-factors are provided in the Metering PTRM, Attachment 0.19 and provided in the table below.

Table 4-8 Revised metering unsmoothed and smoothed annual revenue requirement for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed revenue requirement	20.7	19.6	17.7	15.6	12.5	**86.1**
Revenue X-Factors*	4.08%	4.08%	4.08%	4.08%	4.08%	
Smoothed revenue requirement	18.8	18.0	17.3	16.6	15.9	**86.5**

* A negative revenue X-factor denotes a real revenue increase.

As outlined in section 4.2.2, if re-classified, we propose the metering revenue requirement is added to our SCS revenue requirement utilising an adjustment factor in the control mechanism.

Indicative bill impact

As expected, the socialisation of metering costs over a significantly larger and growing customer base (SCS customers) results in a material reduction in the impact of metering on SCS prices relative to the proposed ACS metering prices. For instance, our proposed metering price for residential customers was increasing from $32.67 in 2024-25 to $48.60 by 2028-29.

The AER's draft decision moved away from the split between capital and non-capital charges for pricing metering as an ACS. This represents a material mitigation of the risk of a dwindling metering customer base being left with exponentially increasing Type 5 & 6 metering prices over the 2024-29 period. Our Revised Proposal builds upon this change by recovering Type 5 & 6 metering costs from all customers as an SCS rather than an ACS. This change, coupled with a reduction in a revised metering revenue, results in lower metering prices as outlined in the table below.

Table 4-9 Metering Draft Decision ACS prices compared to Revised Proposal SCS prices

$pa; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29
Volume weighted average metering price – AER Draft Decision	15.2	15.1	15.2	15.1	15.2
Revised Proposal – SCS metering price	13.0	12.3	11.6	11.0	10.4

The AER's Legacy Metering Services Guidance notes that the AER will consider the pricing impacts of a reclassification, stakeholder feedback and any likely impacts into the 2029-34 period. Whilst an SCS re-classification improves the pricing outcome for metering customers it does mean that all customers contribute towards metering cost recovery.

We consider this to be appropriate for the reasons set out in section 4.3.1, however we are open to feedback from stakeholders and the AER as to whether they consider the benefits of this improved pricing outcome for Type 5 & 6 metering customers outweighs the cost to non-Type 5 & 6 customers. We would welcome further discussion with the AER on this re-classification decision.

4.4. Revised Alternate Control Services Proposal

4.4.1. Public Lighting

The AER's draft decision did not accept Endeavour Energy's proposed public lighting prices for the 2024-29 period. Instead, the AER's draft decision adopted revisions made by Endeavour Energy to its proposal following post-lodgement consultation with the AER and stakeholders.

At the time of our January 2023 Proposal we had engaged extensively with our Public Lighting customers and they were supportive of the proposed Public Lighting modelling approach and resulting prices. However, following additional consideration of our Proposal and benchmarking analysis, WSROC and Wollondilly Council made submissions to the AER highlighting several concerns with our approach to Public Lighting.

In response to this, we engaged with the Councils and the expert consultant, Ironbark, as well as the AER to understand their alternate views. We provided additional evidence to the AER in support of some of our key modelling assumptions such as our LED cleaning cycle and failure rates. We also reflected on the price benchmark analysis and revised our proposed overhead rates (reducing them by 50%) to materially reduce our proposed prices and bring them into alignment with our peers.

Following these changes we consider we have addressed the substantive concerns raised by stakeholders in response to our Proposal. This is reflected in the AER's acceptance of our revised Public Lighting model.

To ensure consistency between the labour assumptions between ANS and public lighting services, we have updated our labour cost escalation forecast and revised labour rates within our Public Lighting model so they reflect the AER's maximum benchmark labour rates. Collectively, these updates result in a marginal average 2.2% increase to the public lighting prices from the draft decision. We propose no other revisions to the AER's draft decision noting it will be updated for movements in the AER's CPI and WACC estimates. Our revised model is provided in Attachment 0.21.

4.4.2. Ancillary Network Services

The AER has not accepted our revised 2024-25 ANS fees and substituted these with lower prices in its draft decision. The AER's prices incorporate more recent data on inflation and real labour cost inputs which resulted in a relatively small reduction to all ANS fees. Updating labour cost assumptions for the latest available data and applying them consistently across all pricing models is appropriate and typically uncontroversial.

Although the majority of our proposed labour rates were accepted on the basis they were below the AER's benchmark maximum labour rate, our rates for the following labour categories were not accepted by the AER:

- EO 7/Engineer – business hours and after hours;
- Field Worker R4 – business hours and after hours; and
- Field Worker R4 (Outdoor) – business hours and after hours[41].

We also note the AER's approved x-factors for 2025-26 to 2028-29 as specified in Table A.1 of the ANS draft decision do not correspond with the values in the draft decision ANS model. We suspect this is because the model contains our proposed values for labour escalation, which were based on an estimate of the KPMG forecast relied upon by the AER. In our revised ANS model we have updated our proposed x-factors for the KPMG labour price forecast contained in the AER's draft decision combined with an updated forecast provided by Oxford Economics Australia.

Our main concern relates to the AER's decision to apply the lowest of either our proposed or their alternate labour rate, despite both sets of rates being derived by applying the Marsden Jacob benchmarking approach simply at different points in time.

[41] In relation to the Field Worker R4 (Outdoor) – after hours labour rate, we note there is inconsistency between the AER's benchmark maximum rate ($343.98; $FY25) and their draft decision rate ($326.07; FY25). The AER's workings in the draft decision ANS model is consistent with Marsden Jacob's recommendation to apply 1.75 times the business hour rate (inclusive of the vehicle allowance component) to obtain after hour rates and supports the former as the benchmark rate to which our proposed rate of $340.10 ($FY25) should be compared. Given our proposed rate is lower than this benchmark, we contend it should have been accepted by the AER.

As part of our early engagement with stakeholders on ANS matters, we made a commitment to rationalise our ANS listing, improve fee transparency by utilising the AER's standardised ANS model and propose benchmark labour rates. This commitment was made in our Preliminary Proposal, reiterated in our Draft Proposal and reflected in our January 2023 Proposal.

As opposed to trending our approved 2019-24 labour rates, we re-established our labour rates by using labour data from the most recent 2022-23 Hays Salary Guide and the methodology established by Marsden Jacob. A step-by-step explanation of how we applied Marsden Jacob's methodology is set out in our January 2023 Proposal.

Importantly, we did not vary our benchmark labour rates to account for factors or circumstances that would have placed upward pressure on our proposed labour rates and ANS fees. These factors include:

- A 36-hour week consistent with the typical working arrangements for our field-based and administrative staff;
- Salary assumptions consistent with those paid to employees in positions that are representative of the ANS labour categories in accordance with the conditions set out in our enterprise bargaining agreements (EBA);
- Salary and wage premiums associated with a workforce located predominantly within the greater Sydney region;
- A tight and increasingly competitive labour market for specialist energy services brought on by a transitioning energy sector and exacerbated by significant investment in network infrastructure via the NSW Electricity Infrastructure Roadmap; and
- Macroeconomic factors such as low unemployment and participation rates which add to staffing and resourcing challenges.

Reasons for discrepancies between benchmark labour rates

The draft decision identifies several changes to the way maximum reasonable benchmark labour rates for 2024-25 have been derived relative to previous AER decisions. The main reason for these changes is the absence of comparable wage data from the 2023-24 Hays Salary Guide for Field Worker and Technical Specialist labour categories which are key inputs for a majority of ANS fees.

For these and the Engineering Manager labour category, the AER has applied the 2022-23 Hays Salary Guide data. For the remaining labour types, the AER has derived benchmark rates using the most recent 2023-24 Hays report. To derive labour rates in 2024-25 terms, the AER has applied either 1 or 2 years' worth of escalation using updated CPI and real wage data as appropriate.

In addition to this, discrepancies between some inputs and assumptions adopted by Endeavour Energy and the AER contribute to the difference in benchmark labour rates. A full and detailed list of discrepancies are listed in Attachment 0.22 to this Revised Proposal.

Despite the differences, our proposed rates were generally comparable to the AER's benchmark maximum rate for most labour categories with the largest discrepancies among the business hour rates observed for Technical Specialist ($11.07), Engineering Manager ($19.97) and Senior Engineer ($74.81). For these labour categories, our proposed rates were below the AER's equivalent benchmark rate.

With regards to the Senior Engineer category, our application of the Marsden Jacob methodology produced a rate that was materially and incongruously lower than the benchmark Engineer labour rate. This is due to the rate for a Transmission Line Design Engineer being higher than the Senior Engineer rates in the 2022-23 Hays Salary Guide and reveals a limitation in using the Hays dataset for benchmarking purposes.

The AER has subsequently updated its approach to apply a 120% uplift to the Engineer rate. We support this change on the basis it avoids this irrational outcome whilst also delivering a Senior Engineer rate that is lower than the Engineering Manager rate by a sensible margin. As a result, we believe our approved 2024-25 Senior Engineer labour rate should also reflect this update.

With regards to the Technical Specialist and Engineer Manager categories, the discrepancies between benchmark rates are broadly driven by the AER's updates to CPI and real wage inputs and the continued application of an allowance to account for salary stickiness in the Hays survey data.

Applying the prevailing benchmarking approach for ANS labour rates

Consistent with its approach in previous determinations, the AER has accepted our proposed labour rates where they are below their benchmarked equivalent. Conversely, where our proposed rates exceed the AER's maximum efficient labour rates, they have been replaced. However, unlike previous proposals our proposed ANS labour rates were derived through an attempt to replicate – without amendment – the AER's benchmark method which has since been updated.

Given this, we believe it is not reasonable for the AER to compare labour rates that have been derived via the same approach albeit with variations only arising due to a change in the prevailing benchmarking methodology and use of updated inputs and assumptions.

We propose that the benchmark maximum labour rates derived by applying the AER's amended and prevailing methodology apply to our ANS fees and quoted services. Our revised ANS pricing model is provided in Attachment 0.22 to this Revised Proposal and incorporates benchmark maximum labour rates for each labour category which are broadly consistent with those derived by the AER in the draft decision ANS model. We have applied updated real wage escalation assumptions which has marginally increased the benchmark rates from those in the draft decision by an average 0.18%.

We have also:

- revised our *Error correction due to incorrect information received from Retailers or Metering Providers (no Site Visit)* service to address the material fee increase from adopting the benchmark Senior Engineer labour rate. Specifically, we have opted to change our labour type and time on task assumptions so that the fee is consistent with the AER's draft decision; and
- proposed new fee and quoted services to accommodate requests to provide access to a metering installation that is secured by our master key. As the AEMC identified, legislation prevents us from sharing network master keys with metering parties and therefore we may be required to provide access to secured sites for the purpose of facilitating a meter installation as part of the LMRP. We have also proposed a minor amendment to the description of the *Access permits, oversight and facilitation* within the service classification table to ensure meter board unlocking activities are unambiguously captured within this service.

Further our revised Nightwatch ANS pricing model is provided in Attachment 0.22 to this proposal. We note the latter reflects the latest energy rates agreed to with our local retailer for this unmetered supply.

Glossary

TERM	DEFINITION
AASB	Australian Accounting Standards Board
ABR	Annual Benchmarking Report
ACCU	Australian Carbon Credits Units
ACS	Alternative control service
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AER CCP	Australian Energy Regulator's Consumer Challenge Panel
AMI	Advanced Metering Infrastructure
ANS	Ancillary Network service
ARR	Annual Revenue Requirement
ATSI	Aboriginal and Torres Strait Islanders
BESS	Battery Energy Storage System
bppa	basis points per annum
BRH	Better Resets Handbook
CALD	Culturally and Linguistically Diverse
Capex	Capital Expenditure
CCF	Climate Change Fund
CECV	Customer Export Curtailment Value
CEFC	Clean Energy Finance Corporation
CER	Customer Energy Resources (previously referred to as DER)
CESS	Capital Efficiency Sharing Scheme
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	Customer Service Incentive Scheme
CWO	Central-West Orana

TERM	DEFINITION
DER	Distributed Energy Resources
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DOE	Dynamic operating envelope
DPPC	Designated pricing proposal charges
DUOS	Distribution use of system
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESCV	Essential Services Commission Victoria
ESIS	Export Service Incentive Scheme
EU	European Union
EV	Electric vehicle
F&A	Framework and approach
FGRG	Future Grid Reference Group
GSL	Guaranteed service levels
GWh	Gigawatt Hour
IASR	Inputs, Assumptions and Scenarios
ICT	Information and Communications Technology
IPART	Independent Pricing and Regulatory Tribunal of NSW
JSA	Jurisdictional scheme amounts
LED	Light-emitting diode
LMRP	Legacy Meter Retirement Plan
MAB	Metering Asset Base

TERM	DEFINITION
MWh	Megawatt Hour
NEM	National Electricity Market
NEO	National Electricity Objective
NPV	Net present value
NSW	New South Wales
NUOS	Network use of system
OECC	Office of Environment and Climate Change (NSW)
Opex	Operating expenditure
PCSC	Peak Customer and Stakeholder Committee
PIAC	Public Interest Advocacy Centre
PQD	Power Quality Data
PTRM	Post tax revenue model
PV	Photovoltaic
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
ReRRG	Retailer Regulatory Reference Group
REZ	Renewable Energy Zone
RFM	Roll-forward model
RIN	Regulatory Information Notice
RIT-D	Regulatory investment test for distribution
ROR	Rate of Return
RORI	Rate of Return Instrument
RRG	Regulatory Reference Group
Rules	National Electricity Rules
SaaS	Software-as-a-Service
SOCI	Security of Critical Infrastructure
STPIS	Service target performance incentive scheme

TERM	DEFINITION
TAR	Total Annual Revenue
TSS	Tariff Structure Statement
UDIA	Urban Development Institute of Australia
VER	Value of Emissions Reduction
WACC	Weighted Average Cost of Capital
WSROC	Western Sydney Regional Organisation of Councils

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