evoenergy

Revised regulatory proposal

Evoenergy electricity distribution determination 2024 to 2029

30 November 2023

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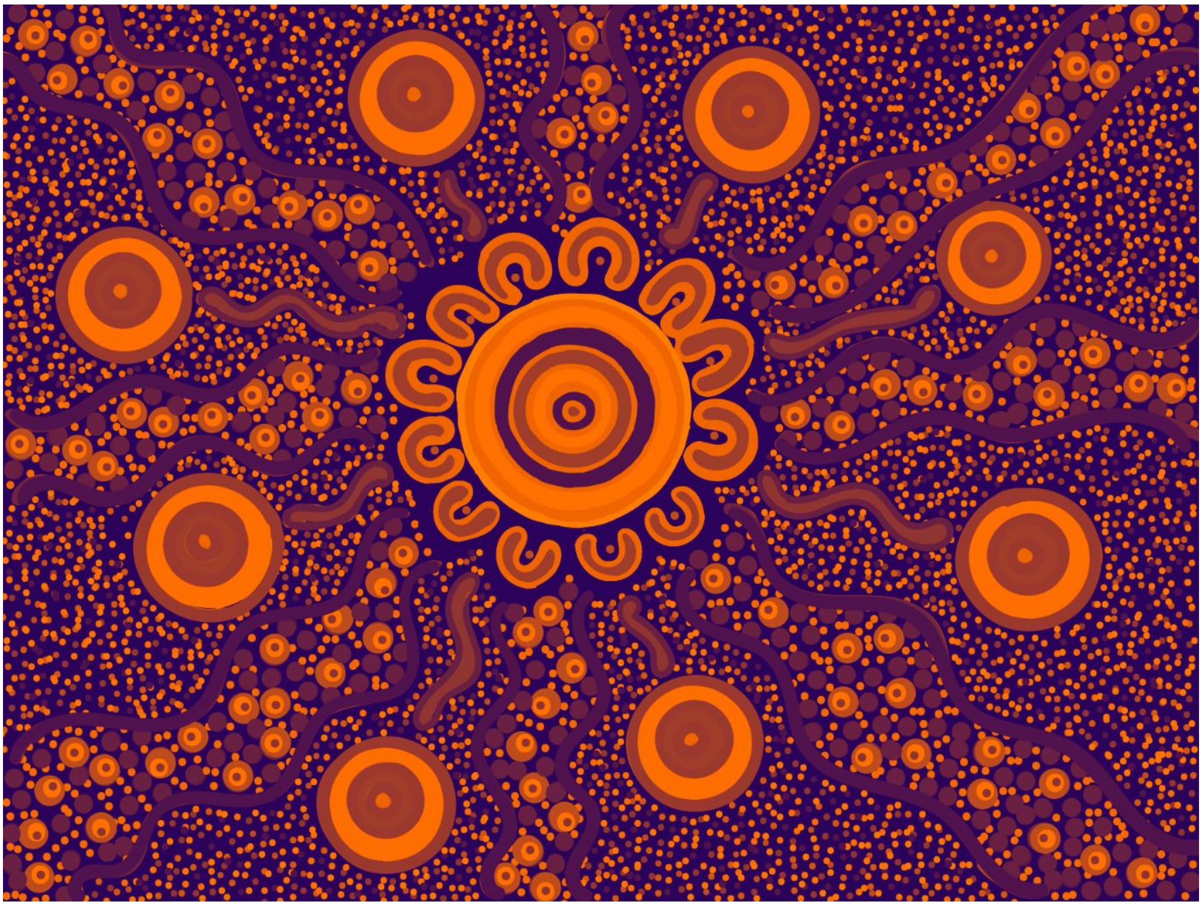
Acknowledgement of Country

Evoenergy acknowledges the Traditional Custodians of the Canberra region, the Ngunnawal and Ngambri peoples, and pays respect to their Elders past and present. We recognise and celebrate all First Peoples' continuing connections and contributions to the regions in which our footprint extends.



Featured artwork: *The Energy of Connection* by Shaenice Allan

Shaenice Allan is a Ngunnawal, Bundjalung and Kamilaroi artist. She has been painting for 15 years, telling the stories that are told to her. Shaenice's paintings represent and connect to the Land of her peoples. The stories are an important part of Shaenice's art. They describe the many stories, the many pathways, and the many lines that connect her to Mother Earth.

Foreword

We are pleased to present Evoenergy's revised proposal for the electricity network for the 2024–29 regulatory period. This follows the September 2023 publication of the Australian Energy Regulator's (AER's) draft decision on our initial proposal.

In the months since our initial proposal was prepared, we have continued to engage with our community as the Australian Capital Territory (ACT)'s push to electrification has gathered pace. Over the past year, electric vehicle (EV) registrations have surpassed previous forecasts, and we have seen new peak demands on our electricity network. Government policy settings have never been clearer, with legislation to prevent new gas connections and achieve the phasing out of natural gas by 2045.

At this early stage of electrification we cannot predict precisely how quickly consumers will choose to transition their homes and businesses from gas to electricity or purchase EVs. With a five-year investment planning cycle, it is difficult to manage this uncertainty. It is possible that Evoenergy may need to invest more than our proposed forecast to support consumers' rapidly changing energy needs.

A fundamental objective of our approach will always be to spend no more than necessary to enable the ACT's energy transition while maintaining a safe and reliable electricity supply. This ensures we continue to play our role in minimising energy cost increases for customers, which is particularly important at present given the current cost of living pressures.

To manage the risk associated with new peak demands on our network while helping our customers manage their energy costs, we are sending strong price signals that enable customers to determine for themselves when to use more or less electricity to help reduce their bills. We are simplifying our tariff structures to ensure these price signals are simple and clear for all customers and are, therefore, more likely to be passed through by energy retailers.

The next five years will be crucial for setting the foundation to enable electrification and the ACT's target of net zero emissions by 2045. We know our community supports this direction and expects us to make the necessary investment to meet changing electricity needs in pursuit of this goal.

John Knox

Chief Executive Officer

Peter Billing

General Manager

Our revised proposal on a page

Our community has told us they need a safe and reliable electricity network to transition the region to a net zero emissions future.

The ACT's net-zero pathway

80-90%

of new vehicle sales will be zero emission vehicles by 2030

by 2045

transition away from natural gas

Our electricity network will transition from currently providing around **one third** to **almost all** of the ACT's energy as we electrify gas and transport

We will enable an estimated **2.4 million** tonnes, worth **$351 million** of network-wide emissions reduction benefits over the next 10 years

We will deliver on our community's priorities by:

Maintaining and operating a safe and reliable network
Our revised operating expenditure forecast is lower than our initial proposal, but the allowance must account for our unique circumstances so that we can maintain a safe and reliable network.

Investing to support the energy transition as electrification of the region drives demand growth
Our revised capital expenditure forecast is in line with our initial proposal and reflects latest information, including on electric vehicles and latest project cost estimates.

Playing our role in energy affordability
Our revised proposal results in average annual bill increases of $16 for a typical residential customer including the impacts of inflation, only $2 more than the AER's draft decision and below our initial proposal.

Playing a key role in enabling customer-owned solar, batteries and electric vehicles
Our expenditure programs include investment in a smarter, future-ready network to enable consumer energy resources.

Simplifying our network tariffs to ensure retailers and consumers can benefit from cost-reflective tariffs
Our revised proposal responds to feedback from consumers and retailers that tariffs need to be easy-to-understand and simple for retailers to implement.

	Initial proposal	AER Draft decision	Revised proposal
Average annual bill increase for residential customers Including the impacts of inflation	$20	$14	$16
Revenue (smoothed) Real June 2024 dollars	$990m	$960m	$1,008m
Operating expenditure Real June 2024 dollars	$390m	$337m	$365m
Capital expenditure Real June 2024 dollars	$521m	$416m	$519m

1. Overview

Evoenergy owns and operates the electricity and gas distribution networks in the Australian Capital Territory (ACT). Our electricity network is made up of poles and wires, underground cables, transformers, substations, and other infrastructure we require to transport electricity to and from homes and businesses. Our role is to deliver a safe and reliable energy supply to homes and businesses in Canberra and the surrounding region. We undertake electricity network maintenance, connect new customers, plan and construct new infrastructure, and provide emergency response.

We charge energy retailers to transport electricity to consumers through our network, and retailers pass on this cost to energy customers through a quarterly or monthly electricity bill. Our costs make up around a quarter of a typical ACT electricity bill.

This document is Evoenergy's revised regulatory proposal for our 2024–29 electricity network regulatory determination (EN24) review submitted to the AER on 30 November 2023 as required under Rule 6.10.3 of the National Electricity Rules (the Rules). It sets out proposed revisions to our operating and investment plans for the period 1 July 2024 to 30 June 2029 to address the AER's draft decision published on 28 September 2023.

Our revised proposal takes into consideration further consumer and stakeholder engagement undertaken since we submitted our initial regulatory proposal to the AER in January 2023. Evoenergy is committed to continuing to collaborate with the AER, consumers, and stakeholders to ensure that our plans reflect their priorities and preferences and to inform the AER's decision-making to deliver a final determination that is in the long-term interests of our consumers.

Our revised proposal materially accepts many of the AER's draft decision positions and focuses on revised positions in the following key areas.

Operating expenditure (opex)	• We have revised our opex forecast using actual expenditure from the latest financial year, which lowers the opex forecast. We do not accept that our base year opex is not materially efficient and have provided additional information to demonstrate the need for the AER to consider our unique circumstances when assessing opex efficiency using its benchmarking approach. • Our revised opex forecast includes additional costs to meet regulatory obligations resulting from the Australian Energy Market Commission's (AEMC's) metering review to facilitate the retirement of legacy meters and the accelerated deployment of smart meters in the ACT, which will deliver benefits to consumers.
Capital expenditure (capex)	• We have updated our augmentation expenditure (augex) forecast to reflect our revised peak demand forecast as well as the latest market tested cost estimates for large zone substation projects. • We have revised our replacement expenditure (repex) proposal to reflect the AER's feedback. We maintain that an uplift on 2019–24 regulatory period expenditure levels for our poles replacement program is required to meet the risk profile of aging assets. Our revised repex forecast also includes expenditure on secondary systems in line with our initial proposal. We have provided further evidence to justify the need for this investment. • We have withdrawn our proposed contingent project based on the AER's feedback on the criteria in the Rules. We remain concerned that the existing regulatory framework does not provide flexibility to manage the demand risk we face. If rapid and broad growth in electricity demand goes well beyond our forecast, additional investment will be required to address network constraints during the period.

Tariffs	• Our revised tariff structure statement (TSS) has been simplified and refined in direct response to stakeholder feedback, the latest demand profile data, and new information about the significant complexity and cost of implementing some of the initially proposed tariffs. This includes the withdrawal of the initially proposed residential export tariff and targeted simplification of the proposed time-of-use tariff. • Our revised TSS includes a new tariff for very large customers connecting to Evoenergy's sub-transmission network for the first time.

Evoenergy's revised regulatory proposal is set out as follows, with a full list of documents provided in Appendix A:

- The revised regulatory proposal (this document) provides an overview of the key factors that have influenced the revisions to our initial proposal, outlines consumer and stakeholder engagement undertaken, and references detailed explanations contained in attachments.
- Five subject matter attachments, including our revised proposed TSS addressing the AER's draft decision and detailing proposed revisions and changes we have made to address matters raised by the draft decision.
- A set of appendices that contain detailed supporting information for this revised proposal and attachments, including a revised indicative pricing schedule and modelling appendix that contains the models used in calculating the figures reported in our revised proposal.

2. The accelerating ACT energy transition

The ACT continues to be at the forefront of the nation's energy transition. The ACT Government has set an ambitious 2045 net zero target, which requires a rapid and extensive reduction in emissions. Natural gas is gradually being phased out. Transport will be decarbonised, with EVs making up 80–90 per cent of new vehicle sales by 2030.

As flagged in our initial proposal submitted to the AER in January 2023, while the net zero target is clear and backed by a strong commitment from the ACT community and government, there is a high level of uncertainty in the medium term. It is unclear when each household will replace their gas appliances and purchase electric vehicles (EVs), as well as how associated behaviours will change. The location and timing of these decisions have a material impact on our investment needs.

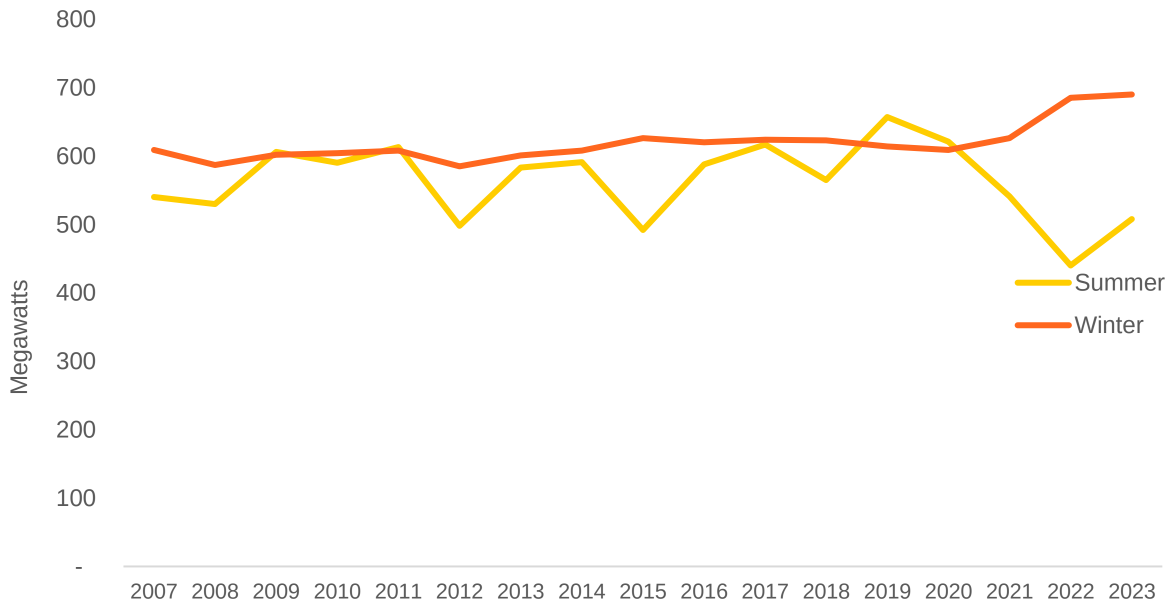
Since submitting our proposal, the data available indicates that both the electrification of transport and gas is occurring much faster than anticipated at the time of developing our initial forecasts.

Electrification of gas is driving an uplift in winter peak demand

Over the last two years, we have experienced record levels of winter peak demand, well above the previous system peak demand record set in summer 2018/19. This change is a departure from the historical trend where winter peak demand has been relatively steady, generally occurring on a weekday evening.

These peak demand events are not outliers. We have seen a sustained and broad-based increase in peak demand. Despite relatively mild winters, over the last two years, we have seen demand above the previous winter record set in 2014/15 on average once a week over June and July 2023 (see Figure 1). Peak demand events are now also occurring in the morning (the current system record was set at 8am) and on the weekend.

Figure 1 Peak system demand (MW)



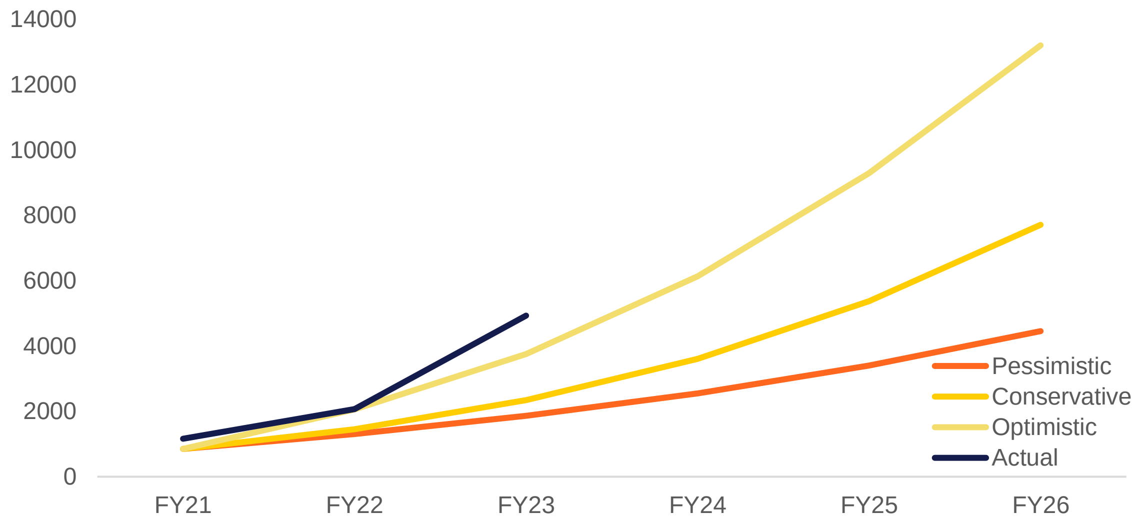
The increase in winter demand is likely due to a faster than expected electrification of gas and we expect that the introduction of significant incentives to substitute gas heating with electric heating in 2021 has played a key role in this trend.

Electric vehicle take-up is outperforming the previous 'optimistic' forecast

We are also seeing a faster than expected take up of EVs. Our initial proposal was based on 2021 projections prepared by Deloitte Access Economics for the ACT Government. Although we based our initial proposal on the 'optimistic' scenario, EV take up has been substantially higher, as can be seen in Figure 2.

We have since obtained an updated independent forecast of EV numbers. This forecast takes into account recent market trends as well as the ACT Government's EV policy released in July 2022. By 2030, we now expect 67,000 passenger EVs on the roads, relative to the previous forecast of 42,000.

Figure 2 Actual and forecast number of EVs



These trends will continue with the ACT Government's Integrated Energy Plan

In August 2023, the ACT Government released its Developing ACT's Integrated Energy Plan (IEP) Position Paper, which outlines the ACT Government's proposed policy directions from now to 2030.

The proposed high-level policy directions are presented in the figure below, and stakeholder and community feedback will inform the development of these in the final IEP, which is expected in early 2024. These policy directions will continue to drive increased demand over the 2024–29 regulatory period and beyond.

Figure 3 IEP proposed policy directions[1]

[1] ACT Government (2023). *Position Paper: Developing ACT's Integrated Energy Plan*, Canberra is electrifying: Towards a net zero emissions city, August, p.9.

3. Revised peak demand forecasts

The electrification of gas and transport energy increases the scale, function and criticality of our network. The network will need to transform from providing largely one-way energy flows to becoming the single crucial platform that underpins almost all energy use in the ACT. The importance and consumer value of a reliable and resilient network has never been greater.

As we have already started to see, the electrification of gas and transport will increase peak demand and place enormous pressure on our network, particularly at the high voltage (HV) feeder and low voltage (LV) levels. Over the next 20 years, our network will require extensive reinforcement to deliver a reliable and resilient supply of energy.

Delayed network augmentation would result in capacity constraints – like those currently seen in the west of London,[2] requiring the ACT's decarbonisation journey to pause while the network catches up to consumer demand. This would lead to higher costs as well as higher emissions and delayed achievement of emission reduction targets, contrary to the updated National Electricity Objective (NEO).

In updating our peak demand forecast for our revised proposal, we refined our forecasting approach to integrate the constructive feedback provided by the AER and incorporate the latest data available. For instance, we have integrated the Commonwealth Scientific and Industrial Research Organisation's (CSIRO's) EV load profiles developed for the Australian Energy Market Operator's (AEMO's) 2024 Integrated System Plan (ISP).

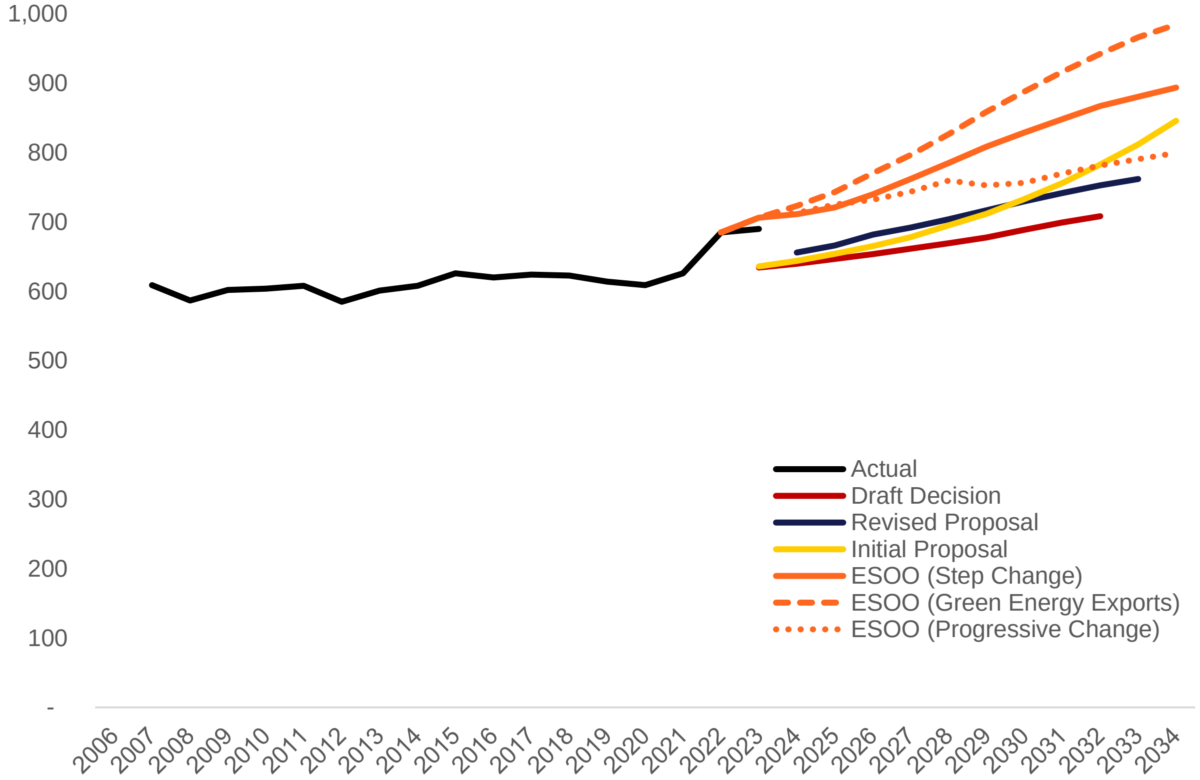
These forecasts include the impact of the roll-out of more cost-reflective tariffs as well as 'managed charging', where retailers or aggregators control EV charging. This ensures there is consistency across our proposed tariffs, peak demand forecast and augmentation requirements.

As shown in Figure 4, we are forecasting that winter peak demand will continue to increase over the 2024–29 regulatory period. Relative to our initial proposal, our revised peak demand forecast starts higher but has a more gradual increase. The reduction in peak demand growth over time is primarily due to applying the CSIRO's updated EV charging profiles.

As a cross check, we have compared our revised forecast against AEMO's forecasts in the 2023 Electricity Statement of Opportunities (ESOO). As AEMO does not prepare an ACT specific forecast, we produced an estimate by calculating an index of average peak demand growth projected for Victoria and New South Wales (NSW).[3] These forecasts are consistent with the forecast prepared by Acil Allen Consulting and GHD for the ACT Government, which forecasts that peak demand will be between 750 – 1100 megawatts (MW) (depending on the scenario) by 2034.[4]

[2] Latest updated from the Mayor of London available here.
[3] This approach was selected on the basis that ACT gas usage is about the average of NSW and Victorian gas usage. Comparisons of peak demand against NSW and Victorian specific forecasts are shown in Attachment 2.
[4] See figures 51, 72, 110 and 145 here.

Figure 4 Winter system peak demand actual and forecasts (POE 50) MW



These cross checks indicate that our revised proposal forecast reflects a conservative view of the likely increase in maximum demand. This is because our forecast does not fully take into account the electrification of gas.

As our existing peak demand forecasting methods are not designed to account for the electrification of gas load and due to the limited data and time available for the revised proposal, it has not been feasible to develop a sufficiently robust post-modelling adjustment which we could apply at the feeder and LV level.[5] Given cost of living pressures and heightened forecasting risks, we have made a conscious decision to adopt a conservative approach and to make no adjustment for gas substitution. This can be seen in the starting point of the demand forecast, which is based on a historical average of observed demand rather than the materially higher recent observations.

[5] We were able to develop a high-level electrification reference case forecast for use as a cross check at the system level. This is outlined further in Attachment 1.

4. Consumer benefits outweigh additional costs

While the energy transition increases investment requirements, these costs need to be considered in the context of the benefits they will deliver in terms of lower overall bills, reduced emissions and whole of energy system cost savings.

All customers will benefit from EVs regardless of whether they own one themselves. Increased network utilisation results in network costs being spread across a greater volume of energy, which will place downward pressure on network prices in the future. For example, without the electrification of transport in the ACT, Evoenergy projects its network charges would be around six per cent higher by 2028/29.

Together with consumer investment in EVs, our network will enable material reductions to petrol and diesel use, reducing consumer costs and emissions. Table 1 sets out our estimate of the network-wide benefits as well as the benefits enabled by EV-driven augmentation. Our estimate is based on the reduction of fuel costs (net of additional electricity costs) and uses the NSW Government's value of carbon emissions as a placeholder. Notably, the value of emissions reductions and avoided fuel costs are materially larger than our proposed investment in EV-driven augmentation ($28 million).

Table 1 Estimated emissions benefits over 2024–29 and 2029–34

	Emissions reductions (tCO_2e)	Value of emissions reductions ($m)	Value of avoided fuel ($m)
Whole network	2,400,649	350.7	1,030.9
Network sections requiring EV-driven augmentation	526,628	77.6	223.7

Note: We calculated benefits over two regulatory periods as the benefits are realised over a time period longer than five years.

The benefits are substantial but not unsurprising, given that by 2034, we expect our network will support over 185,000 EVs. As the ACT has 100 per cent renewable electricity, replacing an internal combustion engine vehicle with an EV removes 2.8 tonnes of carbon dioxide equivalent (tCO_2e) a year. EV owners will also realise fuel savings (net of additional electricity costs) in the order of $1,200 a year.[6]

The emissions reduction benefits our revised proposal will deliver align with the updated NEO, which now incorporates an emissions reduction objective that relates to the achievement of targets that reduce, or contribute to reducing, Australia's greenhouse gas emissions.

[6] Based on an estimate of avoided fuel costs, less additional electricity costs for a typical private vehicle.

5. Increasing cost pressures are being faced by our business and consumers

Broad economic conditions nationally and globally are driving significant upward pressure on the costs of delivering capital works projects. This means, compared with our initial proposal, we are now facing a significant increase in the costs to deliver the projects needed to accommodate the growth in the region's electricity demands.

At the same time, and due to many of the same underlying economic factors, our consumers are experiencing significant cost of living increases, with general consumer inflationary pressure over the last two years reaching the highest levels since the 1990s. We recognise these cost of living pressures can make it hard for some consumers to pay their energy bills and meet their other essential needs. We have heard from the community that they expect us to play our role in ensuring cost increases are minimised, recognising our charges make up around a quarter of a typical electricity bill.

Our revised proposal, therefore, seeks to balance the need to ensure we reflect the step increase in costs to deliver network projects while also ensuring we propose to invest no more than necessary to meet growing customer demands for electricity needed to enable the energy transition.

The following sections set out how we have sought to achieve this balance.

5.1. We have minimised the customer impact of cost increases

Consistent with our initial regulatory proposal, our revised proposal includes an increase in investment compared to the current period to ensure we enable the energy transition to achieve net zero emissions in the ACT by 2045. Our revised proposal also includes efficient market-tested increases in costs for some of our major capital projects, discussed below. In light of the pressure these investments place on electricity bills, we have taken a number of measures to ensure our revised proposal reflects no more expenditure than necessary and costs to our customers are minimised.

As outlined earlier, our revised proposal is based on a conservative demand forecast, which does not account for the electrification of gas. This means we expect to be able to defer new zone substations at Curtin and Mitchell, as well as several feeder and distribution substation projects, minimising costs to customers. As these projects may be required (depending on how fast and where demand grows), we face the risk of these projects not being included in our forecast.

Our new tariff structure, if passed through by retailers, would also give customers the choice to change their energy consumption profile to reduce their overall energy bill, including reducing consumption during peak network periods in the morning and evening and using more energy during the midday 'solar soak' period. For example, by shifting load from the peak period to the solar soak period, a customer could save up to 13 cents per kWh on their network bill,[7] assuming the network pricing signals are directly passed through by retailers.

Our revised proposal includes a lower opex forecast than initially proposed, reflecting efficiencies achieved in the 2022/23 year. Basing our revised proposal off a more recent and lower representative base level of opex will contribute to customer benefits from lower network prices over the long term.

Overall, while our revised proposal involves cost increases to enable the energy transition in the ACT, we have sought to minimise the cost increase by including prudent and efficient costs required to ensure we deliver on the energy transition for the ACT while maintaining a safe and reliable electricity

[7] Based on Evoenergy's proposed residential time-of-use tariff, and the indicative price levels for 2024/25.

supply. Our revised proposal results in an average annual cost increase to our customers of $16 (0.7 per cent) for residential and $89 (0.9 per cent) for small business.

As consumers progressively choose to electrify their households and vehicles through the energy transition, consumption through our network is expected to materially increase, reducing the average cost of electricity for all consumers.

5.2. Our revised major project cost estimates reflect market conditions

To ensure our major projects are delivered efficiently, we select our delivery partners through robust market testing procurement processes. We use third party delivery partners for our major capital works where our internal workforce either has insufficient capacity or technical skills to deliver the project in addition to existing workloads. We typically rely on third parties to design, construct, and commission new zone substations.

At the time of our initial proposal, we forecast the costs of delivering major projects, such as new zone substation developments, based on the costs of delivering projects of a similar scope and scale in the past.

Since our initial proposal, the costs to deliver our major capital projects have increased markedly, including:

- actual costs to date and estimated remaining completion costs for the Harman zone substation have exceeded original expectations; and
- our market testing for the Molonglo zone substation revealed materially higher delivery costs consistent across the available pool of delivery partners.

Costs increases for these projects were driven by both higher labour costs for design, installation and project management, and higher prices for key material inputs such as switchgear and transformers.

Our experience of substantive cost increases is consistent with the experiences of other providers of large capital works projects. For example, AEMO has found transmission projects have increased by over 30 per cent in real terms.[8]

Given the quantum of the cost increase we asked Advisian to review our market testing process and provide an analysis of the cost movement. Advisian found that the market testing process aligned with good industry practice and the observed cost increases are consistent with current market conditions. Advisian's report is provided in Appendix 1.2.

For our revised proposal, we have forecast the costs for the Molonglo and Strathnairn zone substations based on this recent market testing undertaken for the Molonglo zone substation which followed a robust procurement process. Our new cost forecasts for Molonglo and Strathnairn zone substations are broadly aligned with the cost forecasts by other distributors for projects of a comparable nature. More information on our capital project cost forecasts is provided in Attachment 1.

[8] AEMO 2032, *2023 Transmission Expansion Options Report,* September, p.3. Available here

6. Managing uncertainty under the current regulatory framework

The degree of uncertainty associated with the speed of the energy transition and associated customer behavioural responses is unprecedented. It is creating new challenges for the economic regulation of electricity networks globally.

The Australian based regulatory regime, designed for and premised on a steady state, has limited flexibility to manage the type of demand uncertainty created by the energy transition. Regulatory frameworks for electricity networks in other jurisdictions are more adaptable to the changing environment. For example, the United Kingdom's economic regulator recently introduced a suite of demand related uncertainty provisions to manage the energy transition.

Electrification will undoubtedly create new peak demands on the electricity network, and there is a risk that if the electrification of the ACT occurs faster than anticipated, these new peaks will put pressure on the capacity of the network to support this demand, primarily at the HV feeder and LV network levels.

While demand growth at a system or even zone substation level may appear smooth, at the micro level, demand growth is patchy and random. Ultimately, it will be consumer decisions on when to change appliances or when to purchase an EV, which will drive the timing of our investments. This contrasts with typical large transmission level investments, which generally involve a specific location and a small number of connections or decision points. Accordingly, there is a real possibility that the capex in our revised proposal will be insufficient to meet the pace of change in our consumers' needs. If stronger than anticipated demand growth eventuates, we will bear the associated risk, and delays to necessary network infrastructure could slow down our community's action towards the achievement of net zero emissions by 2045.

Engagement with our community throughout the development of our initial and revised proposals has consistently revealed their support for a mechanism that allows Evoenergy to manage the risk associated with the demand uncertainty faced, specifically for the contingent project proposed in our initial proposal. Our consumers consider the achievement of net zero emissions policies to be a priority and expect us to make the investment necessary to enable the energy transition. Our consumers also recognise the difficulty in planning out to 2029 and beyond when there are many uncertainties around the pace of change.

In developing our revised proposal, we have considered the AER's criteria for assessing contingent projects, which do not currently contemplate the type of demand risk we face. The contingent project proposed in our regulatory proposal does not satisfy the location and asset specificity required, and we have therefore withdrawn the contingent project. While an alternative contingent project was considered as part of our revised proposal development, we do not consider nominating a specific project in a specific location based on specific load triggers adequately achieves an effective solution to manage the demand uncertainty created by the energy transition.

We recognise any future reviews of the regulatory framework for managing demand uncertainty would not be implemented in time for the AER's final determination for the 2024–29 regulatory period. Our revised proposal, therefore, relies solely upon the existing provisions within the Rules to reopen the capex decision if unanticipated demand growth leads to additional investment requirements in excess of five per cent of the Regulatory Asset Base (RAB).

We remain concerned, however, that rapid and broad growth in electricity demand across the network will lead to local, spatially diverse, difficult to forecast network constraints and investment requirements, which will not meet any of the available regulatory options to reopen the capex decision. Appendix B provides further explanation of our concerns regarding the inflexibility of the regulatory framework and our reasons for not including a contingent project in our revised regulatory proposal.

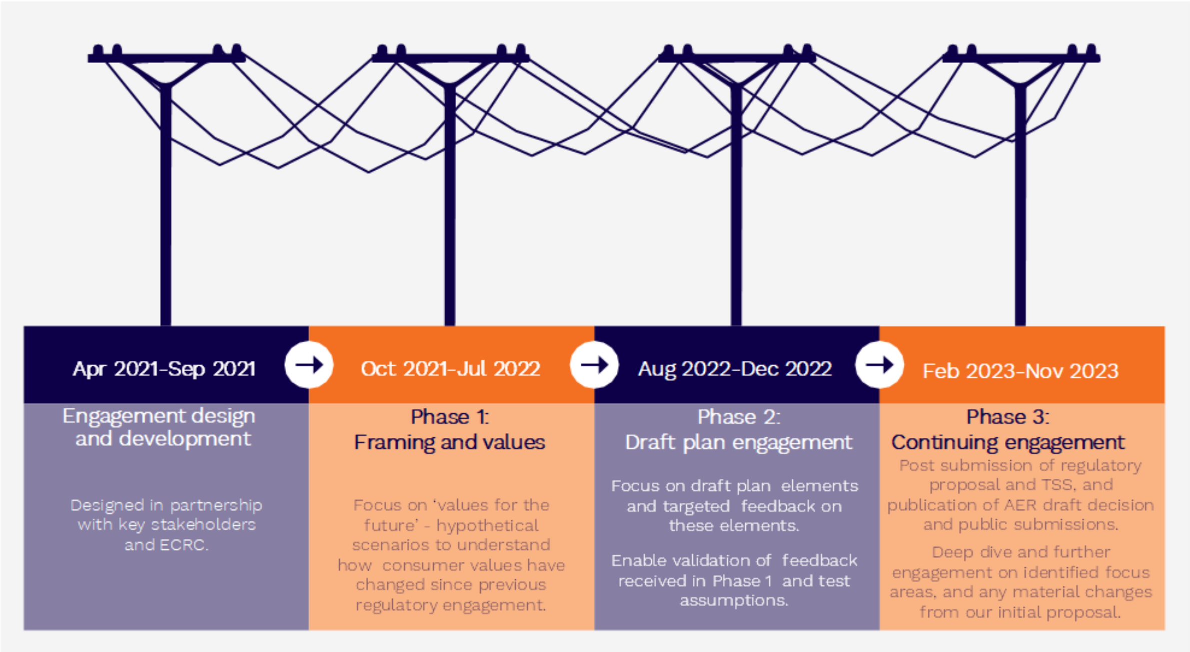
7. Consumers helping to shape our revised proposal

7.1 Our consumer engagement journey

In preparing our regulatory proposal, we made engaging with the community our focus. Building on Phases 1 and 2 of our EN24 consumer engagement strategy[9], we entered the final phase of our engagement program following the submission of our initial proposal to the AER in January 2023. For Phase 3, we have focussed on elements of our proposal that stakeholders had provided further feedback in written submissions[10], as well as those that we expected to change materially between our initial and revised proposals.

A snapshot of our engagement journey is shown in Figure 5.

Figure 5 EN24 engagement journey



[9] Full details of Phases 1 and 2 consumer engagement activities and feedback are available with our initial proposal.

[10] Nine public submissions from the Consumer Challenge Panel (CCP26), ACT Council of Social Service, Conservation Council and other consumer groups, retailers, and the ACT Government.

7.2 Phase 3 engagement

Engagement tools and activities

The feedback we received helped us to refine our approach and bridge identified gaps in our engagement program, enabling targeted engagement, including:

- A review and refresh of our Energy Consumer Reference Council (ECRC) to expand its representative role to reflect better the diversity of Canberra's community and business sector.
- Establishment of a Deep Dive Panel for further and deeper exploration of key issues, challenges, and opportunities in recognition of the pace of change and availability of new information following the preparation of our initial proposal—this included consideration of the need to strike a balance between keeping network tariffs simple while still signalling the efficient costs of using the electricity network and supporting the uptake of renewable energy technology in the ACT. CCP26 members attended all panel sessions held in September and October 2023.
- Engagement with major retailers in the ACT from September to November 2023 to discuss feedback on Evoenergy's proposed TSS and opportunities to simplify our residential tariffs.
- A quantitative survey of EV ownership, charging preferences, responses to price signals and choice-modelling of tariff options for EV charging. The survey was open from September to October 2023.
- A forum with our large customers in November 2023 to gain their unique perspectives on our proposed revised expenditure forecasts and tariff structure changes, including refinement to the capacity charge.
- Better integration of various consumer and stakeholder groups for a broader range of views.

We used various focussed engagement channels and engaged with a number of stakeholder segments, as summarised in Table 2.

Table 2 Summary of Phase 3 engagement

Form of engagement	**Evoenergy's ECRC** *Long-standing consumer reference group* *(Bi-monthly meetings)*	**30-person Deep Dive Panel** *Drawn from our community and pricing panels and new members* *(3 in-person half-day workshops)*	**Quantitative survey** *Targeted research and engagement on EVs and EV tariffs* *(About 700 respondents)*	**One-on-one meetings** *Meetings with major ACT retailers* *(September–November 2023)*	**Energy Matters Forum** *Discussions with major and large customers* *(62 online attendees)*
Residential	✓	✓	✓		
Small-medium business	✓	✓			
Vulnerable communities	✓	✓			
Culturally and Linguistically Diverse communities	✓	✓			
Aboriginal and Torres Strait Islander communities		✓			
Young people	✓	✓	✓		
Retailers				✓	
Large customers	✓				✓
ACT Government	✓				✓

Phase 3 engagement focus areas and themes

The phase 3 engagement activities identified the following key focus areas and themes, which built on consistent themes across all three engagement phases:

- Support for investment in technology and infrastructure to enable the region's energy transition and consumer energy resources (CER), as well as exploring community battery opportunities.

> **Consistent theme across engagement phases:** Take action towards achieving a net zero emissions future and play a key role in enabling consumer energy resources.
>
> *'Community batteries...great idea, gives access to consumers'* – Deep Dive Panel member

- Need for a fair approach to the energy transition that acknowledges potential impacts on vulnerable communities.

> **Consistent theme across engagement phases**: Ensure that no one is disadvantaged or left behind.
>
> *'A potential risk is pricing lower income households out of market'* – Deep Dive Panel member

- Tariff refinements in Evoenergy's revised TSS, including the simplification of our proposed residential tariffs and the removal of the proposed residential export tariff. At the Deep Dive Panel sessions, we also explored future tariff options for EVs.

> **Consistent theme across engagement phases:** Enhanced consumer education on tariffs required due to complexity, involving various parties across the energy sector and governments.
>
> *'A lot more education of consumers required'* – Deep Dive Panel member

- Recognition of the need for flexibility within the regulatory regime to manage uncertainty and ensure the framework does not slow down the energy transition.

> **Consistent theme across engagement phases:** It is important that the regulatory framework recognises the pace of change and provides flexibility to keep pace with the energy transition.
>
> *'The current regulatory cycle (5 years) seems too short given the fast pace of change in energy. Suggest shorter regulatory timeframes or midpoint reviews to adjust spending and investment and to respond to emerging technologies'* – Deep Dive Panel Report

Further details on the discussions and feedback obtained from the Deep Dive Panel, ECRC, and Energy Matters Forum engagement are provided in Appendix C Phase 3 consumer engagement report, prepared by consultant Communication Link. Appendix 4.1 provides detailed information about engagement undertaken to inform the revised TSS. In section 7.3, we address the key areas of feedback from Phase 3 engagement.

7.3 The revised proposal reflects our community's feedback

The revised proposal builds on the consumer feedback that informed the initial proposal to reflect further targeted feedback on consumer priorities and expectations provided through Phase 3, which are summarised in Table 3. Consumers highlighted the rapid evolution of the energy sector, underlining the critical role of consumer education and maintaining adaptability.

Table 3 Consumer priorities and expectations

What we heard during Phase 3 engagement	How we've responded in our revised proposal
Infrastructure investment	
• Network expansion is crucial for ACT's growth. • Future-proofing the network for electrification is a priority, enabling it to handle two-way energy flows and the increased adoption of electrification. • Real data-driven planning decisions are a strength. • Investment should support EVs, community batteries, smart meters and electrification technology. • Long-term investment for network security and stability is vital. • The ECRC encouraged Evoenergy to participate in policy discussions related to meter ownership and renewable energy capacity. • Avoid disadvantaging households and ensure investment strategies benefit all consumers.	• We have revised our peak demand forecast to reflect the latest input data as well as the latest available research and analysis on expected electricity demand over the next decade, which will be a critical phase of the energy transition. This has resulted in some changes to our augex forecast for the period. • Recognising the cost pressures faced by some consumers, we have applied a conservative approach to our demand forecast, which means that we carry additional risk if the increasing demand for electricity accelerates faster than anticipated and additional investment is required during the period. • We have accepted the AER's draft decision to materially accept our proposed CER enablement opex step change. This investment will establish important capabilities during the early stages of transitioning to a future ready network.
Electric vehicle planning	
• Given Canberra's higher rate of EV adoption compared to the national average, Evoenergy needs to ensure that the network can accommodate this growth. • Network tariffs need to support the uptake of EVs and give customers flexibility to meet their EV charging needs. • Infrastructure and technology investments should align with the increasing use of EVs and their impact on the network.	• We have used the best information available to inform our forecasts to ensure we can meet the demands of the ACT's growing EV population. • The tariff reforms in our revised TSS provide more options for EV owners to manage their network bill by choosing when and how fast they charge. EV owners are also able to opt-in to one of Evoenergy's existing controlled load tariffs, which provide a low price for energy used outside of peak times. • We will continue to monitor EV charging behaviour, responsiveness to existing and new tariffs, and emerging network control technology over the 2024–29 regulatory period to inform future tariff reforms.

Tariff changes	
• The Deep Dive Panel and retailers emphasised the need for transparent and easy-to-understand tariffs to empower consumers. • Consumers should feel in control of tariffs and related costs. • Tariffs should provide clear pricing signals to help consumers understand network pricing and encourage balanced adoption of CER like solar, batteries, and EVs. • The removal of the proposed solar export tariff was supported, as it sent mixed signals about the uptake of CER. • Panel members preferred maintaining flexibility in consumer control over EV charging and smart appliances. • Evoenergy was encouraged to play a role in educating retailers and consumers about tariffs.	• Evoenergy has simplified its proposed residential tariffs in the revised TSS. This includes removing the inclining block off-peak charges on the time-of-use tariff and removing the proposed residential export tariff. • Instead of the export tariff, Evoenergy proposes to utilise 'solar soak' charges to reward customers with a lower price for energy 'soaked up' during the middle of the day rather than charging customers for energy exported. Solar soak charges provide a 'softer' introduction to export-based pricing concepts while still helping to manage export-related costs on the network. • Evoenergy's proposed demand and time-of-use tariffs provide cost-reflective price signals throughout the day, which can help inform customer choices about when and how fast to charge their EVs, while still retaining customer flexibility. • Evoenergy will offer its existing controlled load tariffs for EV charging. However, we are not proposing any new controlled load tariffs targeting EVs due to low levels of customer support. • Evoenergy will continue investigations into future-focussed 'flexible load' tariffs that align with advances in technology (such as dynamic operating envelopes, EV 'smart' chargers and other smart appliances). In the future, flexible load tariffs could help manage EV charging on the network without significant impacts on customer amenity. • During the 2024–29 period, Evoenergy will explore further opportunities to inform customers about the new network tariffs and how customers can respond.
Other feedback	
• Concerns were raised about the current five-year regulatory cycle, which may not be suitable for the rapidly changing energy landscape. Shorter regulatory timeframes or midpoint reviews were proposed to adapt to emerging technologies and changing consumer behaviour. • A fair approach that considers vulnerable consumers is important. • The importance of consumer education on tariffs was highlighted, acknowledging the shared responsibility of various parties across the energy sector and governments.	• While the Rules do not currently allow for a regulatory control period shorter than five years, we share the community's concerns regarding the limited flexibility of the current regulatory framework to manage investment risk driven by demand uncertainty as the energy transition gains pace. • We will continue to consider impacts on vulnerable consumers and opportunities for all members of our community to benefit during the energy transition. • We will continue to work with government, retailers and consumers to ensure access to information and education so that consumers can make informed decisions on their energy use.

8. Our revised regulatory proposal

In this section of our revised proposal, we detail our proposed revisions to elements of our proposal in response to the AER's draft decision, updated information, and ongoing stakeholder feedback. A high-level summary comparing our initial proposal, the draft decision and our revised proposal is provided in Table 4 below.

Table 4 Our revised proposal at a glance

Key:

✓ Materially accept draft decision / consistent with AER methodology

– Partially accept draft decision

✗ Do not accept draft decision / not consistent with AER methodology

	Proposal	Draft decision	Revised proposal		Revised proposal position
Standard control services (SCS) opex (see section 8.2)	$390.1m	$336.5m	$364.8m	✗	*Base year efficiency* Do not accept AER draft decision on base year efficiency and propose 2022/23 instead of 2021/22.
				✓	*Trend* Update forecasts using AER methodology
				–	*Step changes* Accept draft decision for insurance and CER integration. Provide further details on Security of critical Infrastructure (SOCI) obligations Propose new step change for the accelerated roll out of smart meters.
SCS net capex (see section 8.1)	$520.8m	$416.3m	$519.4m	–	*Augex* Revised forecast reflects AER feedback and latest information.
				–	*Repex* Revised forecast is below initial proposal and is supported by cost benefit analyses.
				✓	*Other capex categories* Accept draft decision on remaining capex categories, with capitalised overheads forecast updated to reflect revised augex and repex.
Closing RAB value (nominal, end of period) (see section 8.5)	$1,407.8m	$1,279.7m	$1,407.5m	✓	Updated to reflect revised capex forecast.
SCS revenue (smoothed) (see section 8.3)	$990.6m	$960.5m	$1,007.9m	✓	Updated to reflect revised forecasts.

Key:

- ✓ Materially accept draft decision / consistent with AER methodology
- – Partially accept draft decision
- ✗ Do not accept draft decision / not consistent with AER methodology

	Proposal	Draft decision	Revised proposal	Revised proposal position	
Rate of return (year 1)	5.60%	5.81%	5.81%	✓	Placeholder using AER methodology.
Forecast inflation	2.85%	2.80%	2.80%	✓	Placeholder using AER methodology.
Revenue adjustments (see section 8.6)	-$1.9m	$6.4m	$19.8m	✓	Reflects proposed retainment of efficiency benefit sharing scheme (EBSS) and updated capital expenditure sharing scheme (CESS).
Average annual network bill impacts (nominal):					
Residential	$20 increase	$14 increase	$16 increase	✓	Reflects a balance of investment needs and affordability.
Small commercial (see section 8.4)	$119 increase	$76 increase	$89 increase		
Annual energy consumption by end of period	3,109,302 MWh	3,109,302 MWh	3,236,913 MWh	–	Reflects latest EV sales data and forecasts.
Maximum demand by end of period	712 MVA	678 MVA	717 MVA	–	Reflects latest EV sales data and forecasts.
Service classification	Accept service classification as set out in the AER's Framework and Approach (F&A) paper.	Maintain F&A paper positions.	Accept draft decision and propose minor revisions.	✓	We have proposed minor revisions to aim for consistency with changes proposed by NSW distribution businesses as relevant, noting varying positions on legacy metering form of control. Proposed revisions provided in Appendix E.
Control mechanisms	Accept the AER's F&A paper.	Maintain F&A paper positions and invite Evoenergy to reconsider form of control for legacy metering.	Accept draft decision. Maintain alternative control services (ACS) for legacy metering.	✓	
Connection policy	Changes proposed to simplify and reflect changing use of network.	Accepted with agreed amendments.	Accept draft decision.	✓	

Key:

✓ Materially accept draft decision / consistent with AER methodology

– Partially accept draft decision

× Do not accept draft decision / not consistent with AER methodology

	Proposal	Draft decision	Revised proposal	Revised proposal position
Incentive schemes (see section 8.6)	✓ EBSS ✓ CESS ✓ STPIS ✓ CSIS ✓ DMIS and DMIAM	× EBSS ✓ CESS ✓ STPIS × CSIS ✓ DMIS and DMIAM	✓ EBSS ✓ CESS ✓ STPIS × CSIS ✓ DMIS and DMIAM	– Proposal to retain EBSS due to position on opex efficiency.
Pass throughs	Proposed four nominated pass through events.	Accepted proposed nominated pass through events, with minor amendments.	Accept draft decision.	✓
Contingent projects	Proposed contingent project, triggered by material increase in demand.	Contingent project not accepted on basis that triggers do not meet criteria in terms of specificity.	Contingent project not proposed due to difficulty in satisfying AER criteria.	✓ While contingent project criteria cannot be met, concern remains about suitability of existing regulatory framework to manage demand risk.
Tariffs (see section 8.7)	Progressed tariff reforms including: • Introducing new residential demand and time-of-use tariffs; • introducing 'solar soak' • charges; and • introducing residential export charge and rebate.	Materially accepted major aspects of the proposed TSS. Require Evoenergy to consider tariff options to help manage EV charging load.	• Withdraw proposed export charge and rebate. • Targeted simplification of the proposed time of use tariff. • Utilising the new residential tariffs, and existing controlled load tariffs, to send price signals for EV charging. • Accept other aspects of draft decision.	– Proposed revisions to TSS to reflect consumer and retailer feedback on need for tariff simplification.
Ancillary network services (ANS) (see section 8.8)	Proposed new services, removed redundant services, and revised cost build up for services.	Accepted new services and materially accepted most service prices. Did not accept contractor and material costs for some services, or our proposed crew size for connection services.	• Maintain initial proposal on ancillary network services.	– Provide further evidence to support the efficiency of contractor and material costs and the crew size for connection services.

8.1. Capital expenditure

AER draft decision

In our January 2023 regulatory proposal, we proposed a (net) capex program of $520.8 million ($2023/24). The program included an uplift in augmentation investment to provide the additional capacity necessary to accommodate the increase in peak demand driven by ongoing population growth, the rapid take up of EVs and electrification of gas as part of the ACT Government's ambitious 2045 net zero target.

While the AER did not accept our total forecast in totality, it was broadly supportive of our forecasting approach. It found that our asset management practices are consistent with good industry practices and that we conducted genuine consumer engagement on our capex proposal.

The AER's draft decision was to allow $416.3 million of capex for Evoenergy over the 2024–29 regulatory period, which amounted to a 20 per cent reduction in capex from our proposal. The AER identified two key components of Evoenergy's capex forecast—augex and repex —where it required more information before it could be satisfied with our forecast.

- **Augex –** the AER acknowledged the enormity of the energy transition underway and identified the need to provide an updated demand forecast. The AER developed a placeholder demand forecast (which it indicated should not be considered realistic) and used this to estimate our augmentation requirements. The AER accepted almost all of our non-EV demand driven projects but only one of our EV-demand driven projects. This resulted in an augmentation forecast of $103.9 million[11] compared to our initial proposal of $181.6 million, a reduction of around 43 per cent. The AER identified several opportunities to enhance our forecast. It indicated that it would undertake a further assessment of both our demand forecast and augmentation requirements following the submission of our revised proposal.
- **Repex –** the AER considered Evoenergy had not provided sufficient risk based economic analysis to justify the proposed increase in repex over historical levels. As a result, the AER only allowed $94.4 million of Evoenergy's proposed $117.6 million, a reduction of around 20 per cent. The AER was open to receiving further justification for Evoenergy's key repex programs, particularly where they involve an uplift on recent historical levels.

For other capex categories (e.g. non-network, connections) the AER accepted Evoenergy's proposal, with the exception of capitalised overheads. For capitalised overheads, the AER allowed $81.6 million of Evoenergy's proposed $87.6 million, a reduction of around seven per cent. This reduction occurred as a modelling adjustment by the AER, as 'capitalised overheads are an allocated portion of total forecast capex'.[12] In other words, due to the AER's decisions on augex and repex, the overall capex program fell, leading to lower capitalised overheads.

Revised proposal

Our revised capex proposal provides additional supporting documentation and updates in inputs since the submission of our initial proposal. It also considers the outcomes of further consumer engagement activities and matters raised by the AER and its consultants. Our revised capex program reflects the efficient costs required to meet the capex objectives in the Rules, to meet expected demand for electricity network services, comply with our regulatory obligations, ensure we maintain quality, reliability and security of supply and continue to operate the network safely.[13] Our revised capex

[11] Note, the AER listed $104.6 million as the draft decision amount on p.8 of its decision, but the AER's draft decision standardised capex model gave $103.9 million for augex when Evoenergy substituted in its original inflation and escalation assumptions, i.e. to back out 'modelling adjustments' as the AER had done in its draft decision. The AER's draft decision refers to $103.9 million for augex in Table 5.4 on p.7 of its decision.
[12] AER 2023, *Draft decision for Evoenergy determination*, Attachment 5 Capital expenditure, p 9.
[13] The Rules, Clause 6.5.7(a).

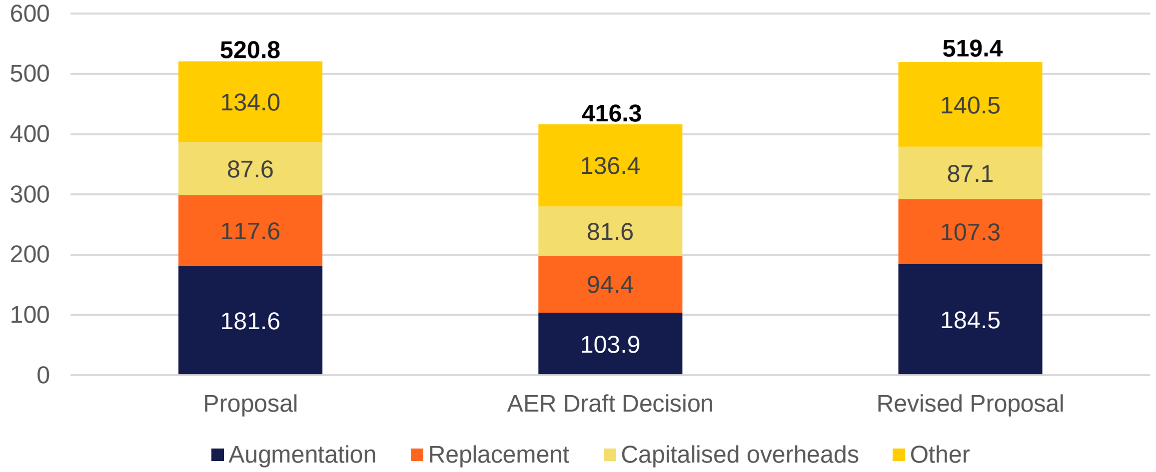
proposal enables our consumers' electrification journey to meet the ACT government's net zero by 2045 emissions reductions target.

Table 5 Evoenergy's response to the AER's draft decision on key capex components

Capex forecast	Initial proposal	AER draft decision	EN24 revised proposal
Augex	$182m	Partially accepted	Consistent with the recommendations in the AER's draft decision, we have refined our peak demand forecasts, incorporated the latest information available and reviewed our forecast augmentation requirements. Broadly, we found that all of the projects accepted (largely non-EV-demand driven) were still required but that the market costs of our zone substations had increased. In respect of our EV-demand driven projects, we found that investment is still required, but to a lesser extent than we had initially proposed. Overall, these two changes offset each other, resulting in a forecast of $184.5m, similar to our initial proposal. **Attachment 1 – Augmentation expenditure** provides further detail on our updated peak demand forecast and how to forecast our augmentation requirements.
Repex	$118m	Partially accepted	Partially accept draft decision. Evoenergy has accepted a partial reduction to its proposed repex program. However, it still viewed some uplift on the AER's draft decision was required to meet our regulatory obligations relating to reliability. For poles and secondary systems, Evoenergy has included business cases to support why an increase over recent historical repex levels is appropriate for these two categories over the EN24 period. **Attachment 2 – Replacement expenditure** contains a fuller justification for Evoenergy's proposed repex program.
Connections	$123m	Accepted	Accept draft decision.
Non-network	$68m	Accepted	Accept draft decision.
Capitalised overheads	$88m	Partially accepted	Partially accept draft decision. Capitalised overheads have been calculated in accordance with Evoenergy's standard methodology in reference to the proposed capex program.

Figure 6 shows Evoenergy's revised (net) capex program is for a total of $519.4 million ($2023/24), which is a 24.8 per cent increase on the AER's draft decision amount of $416.3 million.

Figure 6 Revised capex forecast ($ million, 2023/24)



Note: 'Other' includes all other components of net capex, such as non-network capex, connections, capital contributions, disposals and modelling adjustments.

Table 6 Revised capex program and comparison to the regulatory proposal and AER draft decision ($ million, 2023/24)

Category	Regulatory proposal	Draft decision	Revised proposal	Change to regulatory proposal (%)	Change to draft decision (%)
Augmentation	181.6	103.9	184.5	1.6%	77.5%
Replacement	117.6	94.4	107.3	-8.8%	13.7%
Connections	122.5	122.5	122.5	0.0%	0.0%
Property	2.9	2.9	2.9	0.0%	0.0%
Information and Communications Technology	39.0	39.0	39.0	0.0%	0.0%
Fleet	13.8	13.8	13.8	0.0%	0.0%
Non-network capex – other	12.3	12.3	12.3	0.0%	0.0%
Capitalised overheads	87.6	81.6	87.1	-0.6%	6.8%
Gross capex	**577.5**	**470.6**	**569.6**	**-1.4%**	**21.0%**
Capital contributions	(52.6)	(54.2)	(52.7)	0.2%	-2.8%
Disposals	(4.2)	(4.2)	(4.2)	0.0%	0.0%
Modelling adjustments	-	4.1	6.6	n.a.	61.8%
Net capex	**520.8**	**416.3**	**519.4**	**-0.3%**	**24.8%**

Note: Totals may not sum due to rounding.

‘Modelling adjustments’ in Table 6 reflects updates to inflation and cost escalation factors in the AER’s standardised capex model. Inflation has been updated for further actual data published by the Australian Bureau of Statistics and updated forecasts from the Reserve Bank of Australia in its Statement of Monetary Policy, with the August 2023 iteration used for the revised proposal. Evoenergy has accepted the AER’s removal of escalation to contract labour in the standardised capex model and retained a zero real cost escalation forecast for non-labour costs, per the approach of the initial proposal.

For internal labour (proxied by EGWWS[14] labour), Evoenergy has applied the AER’s methodology. Under this methodology, the appropriate EGWWS labour escalation factor is the average of the updated Oxford Economics[15] and KPMG forecasts, with an allowance for changes to the Superannuation Guarantee (SG) charge. For transparency, the derivation of cost escalation factors used in the capex model for internal labour (EGWWS) is shown below in Table 7.

Table 7 EGWWS real cost escalation derivation

	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Oxford Economics (=A)	-3.59%	-0.27%	1.31%	1.10%	0.80%	0.66%	0.96%
KPMG (=B)	-3.23%	0.51%	0.08%	0.61%	0.85%	0.93%	0.95%
Average (=[A+B]/2=C)	-3.41%	0.12%	0.69%	0.85%	0.82%	0.79%	0.95%
SG increase (=D)	0.50%	0.50%	0.50%	0.50%	0.0%	0.0%	0.0%
Final EGWWS (=C+D)	**-2.91%**	**0.62%**	**1.19%**	**1.35%**	**0.82%**	**0.79%**	**0.95%**

[14] Electricity, Gas, Water and Waste Services.
[15] Attachment A, Oxford Economics 2023*, Electricity-Related Labour Escalation Forecasts to 2028/29*.

8.2. Operating expenditure forecast

AER draft decision

The AER's draft decision included an alternative opex forecast of $336.5 million, reducing our initial opex forecast by $53.6 million or 13.7 per cent. The AER's draft decision to include an alternative opex forecast was primarily based on concerns regarding the efficiency of the 2021-22 base year. The AER's draft decision made the following adjustments to the opex forecast compared with our initial regulatory proposal:

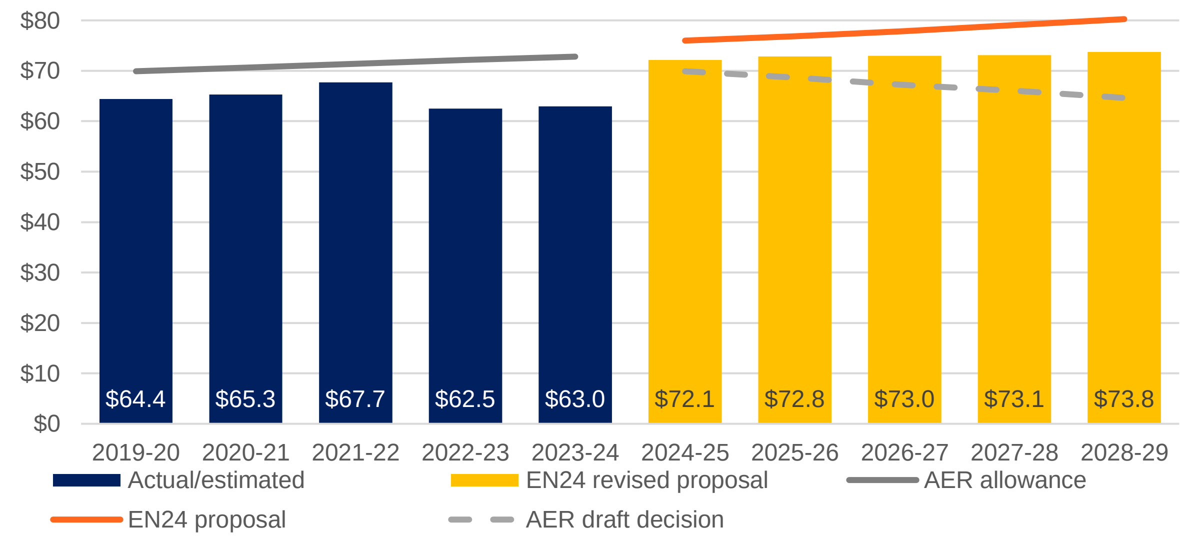
- a substituted opex base year from which to trend the forecast, based on the AER's benchmarking analysis, which considered that the 2021/22 base year opex was inefficient;
- applied a 15.7 per cent efficiency adjustment, partially offset by a linear transition path to reflect the costs of achieving improved efficiencies during the 2024–29 regulatory period;
- reduced our CER step change to exclude expenditure associated with enabling and managing community batteries;
- lowered the output growth forecast to reflect a reduced demand forecast, and a different circuit length forecast consistent with that reported in our Reset Regulatory Information Notice (RIN); and
- Updated the labour price growth forecasts for applying an average of Oxford Economics' forecasts and a KPMG forecast and adding the legislated Superannuation Guarantee increase.

The AER's draft decision accepted our initial proposal step change for increasing insurance premiums. It included a placeholder step change for the SOCI costs pending further assessment of the efficiency of the proposed costs for the final decision.

Revised proposal

Evoenergy's revised opex forecast is $364.8 million for the 2024–29 regulatory period. Our revised opex forecast is $25.3 million or 6.5 per cent lower than the initial regulatory proposal, and $28.3 million or 8.4 per cent higher than the AER's draft decision, as shown in Figure 7. Our revised opex forecast reflects the views of consumers. The forecast is prudent and efficient, capturing costs to provide safe and reliable electricity supply, meet current and expected regulatory obligations, manage demand, and maintain current service standards expected by our consumers.

Figure 7 Revised opex forecast ($ million, 2023/24)



The revised opex forecast by component is shown in Table 8, with more information provided in Attachment 3 and the supporting appendices.

Table 8 Revised opex forecast ($ million, 2023/24)

Opex forecast	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Base opex	63.0	63.0	63.0	63.0	63.0	**314.8**
Trend	8.0	8.1	$7.7	7.4	7.6	**38.8**
Step changes	0.6	1.2	$1.7	2.1	2.6	**8.2**
Debt raising costs (DRC)	0.6	0.6	0.6	0.6	0.6	**3.1**
Opex forecast	**72.1**	**72.8**	**73.0**	**73.1**	**73.8**	**364.8**

Note: Totals may not sum due to rounding.

The key components of our revised opex forecast and how each component differs from our initial proposal and the AER's draft decision are detailed in Table 9.

Table 9 Summary analysis of key components of the opex forecast

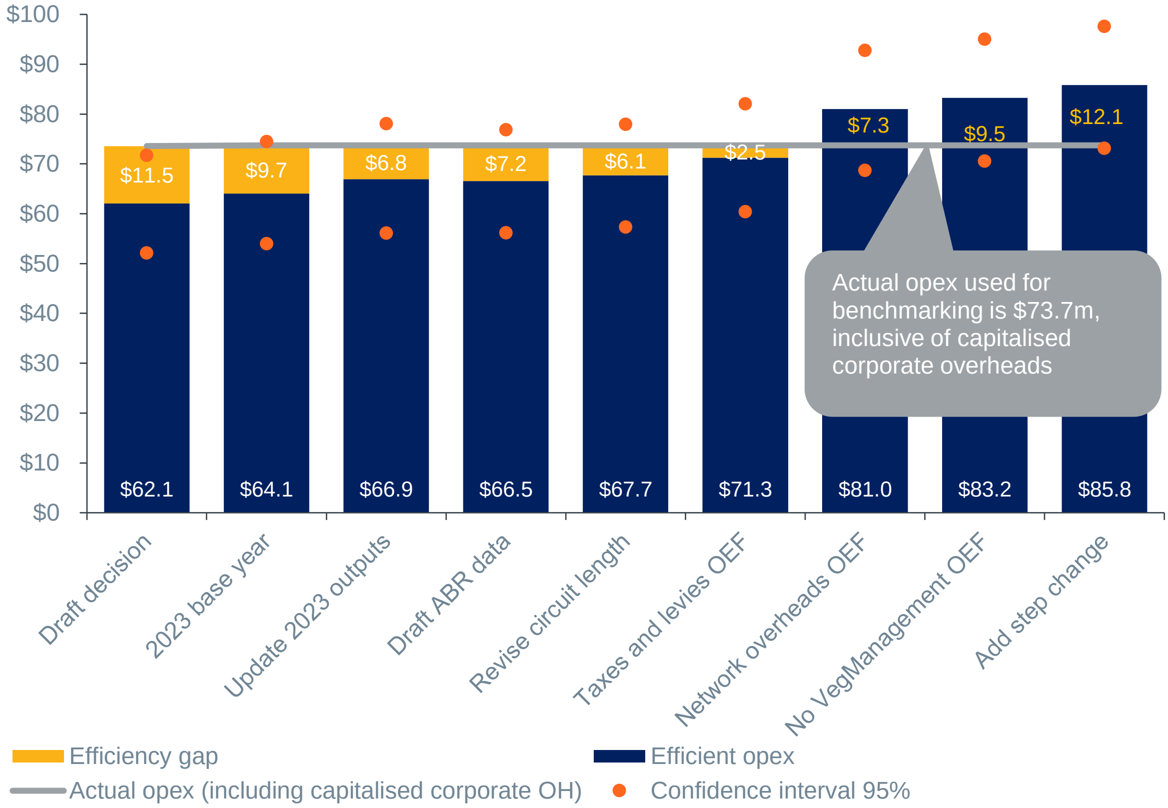
Opex forecast	EN24 initial proposal	AER draft decision	EN24 revised proposal
Base opex and efficiency	Evoenergy proposed a 2021/22 opex base year and considered that it was efficient based on accounting for our distinct operating environment.	Determined that the proposed 2021/22 opex base year was materially inefficient and substituted revealed opex with an alternative estimate based on the AER's opex roll forward approach.	We have updated our opex base year to 2022/23, which substantially decreases the opex forecast by $26.7m or 7.3 per cent. Evoenergy considers that our updated opex base year is efficient, and better reflects recurrent expenditure. We have included additional data and information to demonstrate opex efficiency.
Final year increment	Applied the AER's standard approach, consistent with the formula defined in the AER's Expenditure Forecast Assessment Guideline.	As the base year was considered materially inefficient, an alternative estimate for the proposed base year was rolled forward using the rate of change.	Given that Evoenergy has updated our efficient opex base year to 2022/23, we have updated the calculation using the AER's preferred final year increment formula.
Real price change	Applied real labour cost escalators based on Oxford Economics' forecasts, using the AER's benchmark labour weight.	Updated real labour cost escalators to account for the SG, averaging the forecast with the AER's consultants forecast.	Accept AER's draft decision, updated to reflect more recently available data captured in the Oxford Economics' forecast.

Opex forecast	EN24 initial proposal	AER draft decision	EN24 revised proposal
Output change	Apply AER's methodology to include an allowance for growth in customers, maximum demand, and circuit length.	Updated maximum demand and circuit length, to reflect lower demand forecast and information included in the Reset RIN.	Updated customer numbers, circuit length and maximum demand to reflect actual data for 2022/23. We have also adopted the output weights derived in the Draft AER 2023 Annual Benchmarking Report.
Productivity growth rate	Adopted the AER's estimated industry frontier shift in productivity, based on its final decision for forecasting productivity growth in 2019.	Accepted Evoenergy's proposed productivity growth rate.	Accept the AER's draft decision.
Step changes	Proposed step changes for: • Insurance premiums; • SOCI Act obligations; and • CER integration.	• Accepted the proposed step change for insurance premiums. • Included a placeholder for SOCI obligations. • Partially accepted the proposed CER integration, except for the costs associated with community batteries.	• Accept draft decision on insurance premiums. • Accept the draft decision on CER integration. • Provide further information on SOCI. • Propose new step change for regulatory obligations for the roll out of smart meters following the AEMC's review.
DRC	Estimated using the AER's methodology.	Updated to reflect a draft decision on capex.	Updated to reflect the revised capital program.
Opex forecast	**$390.1m**	**$336.5m**	**$364.8m**

Opex base year efficiency

We consider that our updated 2022/23 opex base year is efficient when capturing the impacts of our unique operating environment, accounting for statistical uncertainty, and acknowledging limitations of the AER's benchmarking models, which present serious statistical issues, rendering them unfit to be deterministically applied when setting revenue allowances. Using the AER's econometric cost function model and the AER's opex roll forward approach to assess opex efficiency, Figure 8 shows the quantitative cumulative impacts detailing how we have concluded that the 2022/23 opex base year is efficient.

Figure 8 Operating expenditure stepped efficiency analysis ($ million, 2022/23)



Source: Appendix 3.1 AER Benchmarking of DNSP opex, November 2023.

The main drivers contributing to the assessment of opex base year efficiency include:

- Updating the opex base year from 2021/22 to 2022/23, reflecting more recently available information and a more representative base. Evoenergy considers that our updated opex base year is efficient, and better reflects recurrent expenditure. The updated base year substantially decreases the opex forecast by $26.7 million or 7.3 per cent, providing cost savings to our customers.
- Adopting the impacts of the Draft AER 2023 Annual Benchmarking Report, which was available at the time of deriving the revised opex forecast.
- Ensuring that our data is correct, and reflects definitions in the AER's RIN, including reinstating historical circuit length for 2006 to 2020, and corrected circuit length for 2021 and 2022.
- Including a taxes and levies operating environment factor (OEF) as the ACT pays a higher payroll tax compared to the networks it is benchmarked against.
- Controlling for Evoenergy's unique approach to expensing network overheads to capture idiosyncratic historical practices, representing outlier characteristics relative to other networks we are compared against. Evoenergy has historically expensed 100 per cent of network overheads, compared to the customer-weighted industry average of 62 per cent, which materially impacts how base year opex efficiency is assessed. When our distinct expensing practices are accounted for using a post modelling adjustment to the AER's benchmarking analysis, Evoenergy's base year opex efficiency gap is reduced by $9.8 million.
- Adequately accounting for additional vegetation management regulatory obligations in the AER's opex roll forward approach to recognise cost impacts at a particular time rather than through an OEF adjustment applied to the average rolled forward opex over the entire benchmarking period.

Our revised regulatory proposal details how statistical uncertainty should be quantitatively captured to inform efficiency analysis. It highlights serious statistical issues identified in the AER's benchmarking models, which, in our view render results unreliable for setting regulatory allowances. Evoenergy considers that confidence intervals can be used to transparently inform statistical uncertainty of a point estimate derived from the AER's econometric models rather than exclusively relying on mere regulatory judgement. In Appendix 3.1, Frontier Economics evaluates evidence demonstrating that serious statistical issues are a likely outcome of fundamental misspecification of the AER's econometric cost function models, partially explained by the embedded assumption that network efficiency has remained constant over time, despite the AER acknowledging that distribution network service provider opex efficiency has improved over time. While we understand that there are timing limitations in interrogating model specification with networks, we consider that the AER should not deterministically apply the outcomes of their benchmarking models and should interpret the results with caution and accounting for statistical uncertainty.

We consider our opex forecast prudent and efficient, forecasting from an efficient updated 2022/23 base year. Given that our revised proposal accounts for our distinct operating environment to allow for a more comparative opex efficiency analysis, and in the context of statistical uncertainty and statistical issues with the benchmarking models, our revised opex forecast cannot be considered materially inefficient with any level of confidence.

8.3. Revised forecast revenue

AER draft decision

The AER's draft decision calculated a revenue forecast using a building block approach under a revenue cap control mechanism. The AER's draft decision total revenue forecast is $960.5 million ($2023/24) and is summarised in Table 10.

Table 10 AER draft decision smoothed revenue requirement ($ million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution	**158.3**	**168.6**	**164.4**	**160.3**	**156.2**	**807.7**
Distribution X-factors		–6.50%	2.50%	2.50%	2.50%	
Transmission	**31.0**	**32.1**	**31.0**	**29.9**	**28.9**	**152.8**
Transmission X-factors		–3.50%	3.50%	3.50%	3.30%	
Total revenue requirement (smoothed)	**189.3**	**200.7**	**195.3**	**190.1**	**185.1**	**960.5**

Note: The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

Revised proposal

Evoenergy’s revised proposal building block revenue requirement is $1,007.3 million (unsmoothed) and is set out in Table 11. Table 12 and Table 13 show Evoenergy’s revised proposal building block revenue requirements for our distribution and transmission network assets, respectively.

Table 11 Total building block revenue requirements (unsmoothed) ($ million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Return on capital	63.7	65.9	67.3	69.1	71.8	337.8
Regulatory depreciation	56.3	63.3	54.5	55.0	44.7	273.7
Opex	72.1	72.8	73.0	73.1	73.8	364.8
Revenue adjustments	5.7	3.1	4.0	6.1	0.8	19.8
Net tax allowance	2.5	3.0	2.2	2.8	0.6	11.1
Revenue requirement	**201.0**	**210.2**	**201.0**	**206.1**	**191.7**	**1,007.3**

Note: Totals may not sum due to rounding.

Table 12 Building block revenue requirement (unsmoothed) – distribution ($ million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Return on capital	53.0	54.8	56.0	57.8	60.1	281.7
Regulatory depreciation	47.3	53.2	45.5	46.4	37.4	229.7
Opex	60.7	61.3	61.5	61.6	62.1	307.2
Revenue adjustments	5.2	3.0	3.8	5.6	1.1	18.6
Net tax allowance	1.9	2.3	1.6	2.1	0.1	7.9
Revenue requirement	**168.1**	**174.6**	**168.3**	**173.4**	**160.7**	**845.1**

Note: Totals may not sum due to rounding.

Table 13 Building block revenue requirement (unsmoothed) – transmission ($ million, 2023/24)

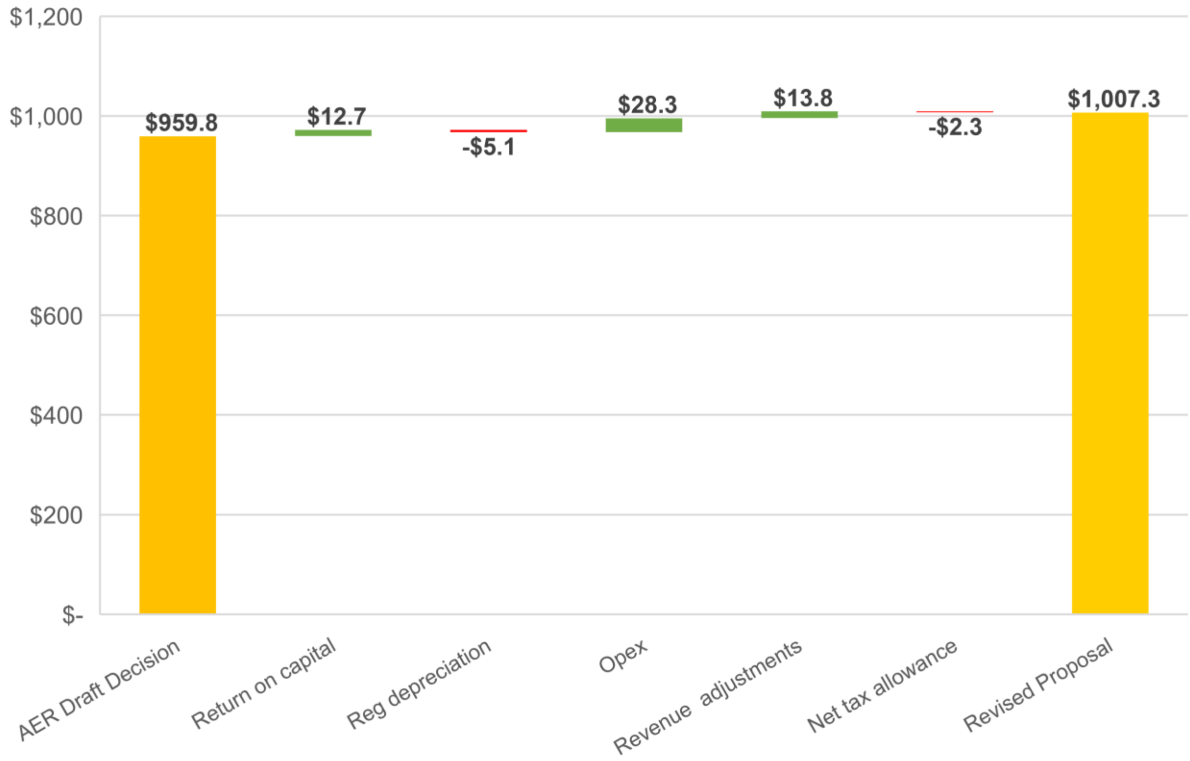
	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Return on capital	10.8	11.2	11.2	11.3	11.7	56.2
Regulatory depreciation	9.0	10.1	9.0	8.6	7.3	44.1
Opex	11.4	11.5	11.5	11.5	11.6	57.6
Revenue adjustments	0.5	0.1	0.2	0.6	-0.3	1.1
Net tax allowance	0.6	0.8	0.7	0.7	0.5	3.2
Revenue requirement	**32.3**	**33.6**	**32.7**	**32.7**	**30.9**	**162.2**

Note: Totals may not sum due to rounding.

Evoenergy accepts the AER's draft decision in relation to the methodology for calculating the net tax allowance, return on capital and regulatory depreciation building blocks, noting they will be updated for the AER's final decision. The AER calculates Evoenergy's rate of return using a methodology set out in its 2022 Rate of Return Guideline. Evoenergy accepts the AER's methodology, noting the calculation will be updated for its final decision.

Our revised proposal revenue requirement is 4.9 per cent higher than the AER's draft decision and 9.2 per cent higher than the current 2019–24 regulatory period. A breakdown of the movements between periods is shown in Figure 9. The increase between the draft decision and the revised proposal is largely driven by higher forecast opex and revenue adjustments, with the latter reflecting our revised proposal to maintain the EBSS.

Figure 9 Comparison of total unsmoothed revenue requirement ($ million, 2023/24)



Smoothed revenue requirement

To minimise year on year variability in prices, we have smoothed revenues over the 2024–29 regulatory period. Table 14 shows the X factors that show the after-inflation price change required in each year.

We have set the X factors to minimise the variance between building block revenue and the smoothed revenue required for the last regulatory year. The AER considers that a divergence of up to three per cent is reasonable if this can promote smoother price changes over the regulatory period. To achieve this, we require a larger real price increase upfront, followed by real price reductions later in the regulatory period. However, we are open to discussing this matter with the AER to consider if a different smoothed revenue requirement is more appropriate.

Table 14 Smoothed revenue and X factors ($ million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution						
Smoothed revenue	161.9	176.4	172.7	169.1	165.5	845.6
X-factors	–9.40%	–8.93%	2.10%	2.10%	2.10%	n/a
Transmission						
Smoothed revenue	31.2	33.7	33.1	32.5	31.9	162.3
X-factors	–6.45%	–8.02%	1.85%	1.85%	1.85%	n/a
Total						
Smoothed revenue	193.1	210.1	205.8	201.5	197.4	1,007.9

8.4. Indicative bill impacts

AER draft decision

The AER's draft decision indicative bill impacts are summarised in Table 15. The AER's draft decision would see the distribution component of network bills increase by 0.1 per cent, and the transmission component of network bills decrease by 1.2 per cent on average through the 2024–29 regulatory period in nominal terms. This is about $14 a year for residential customers and $76 per year for commercial customers on average over the period.

Table 15 AER draft decision annual electricity bill impacts (nominal)

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Average
Residential annual electricity bill	$2,267	$2,306	$2,343	$2,341	$2,338	$2,336	
Annual change	–	$39 (1.7%)	$37 (1.6%)	–$2 (–0.1%)	–$3 (–0.1%)	–$2 (–0.1%)	$16
Small business annual electricity bill	$9,572	$9,782	$9,987	$9,978	$9,964	$9,952	
Annual change	–	$210 (2.2%)	$205 (2.1%)	–$9 (–0.1%)	–$14(–0.1%)	–$12 (0.1%)	$89

Revised proposal

Our revised proposal indicative bill impacts are summarised below in Table 16. Our revised proposal would see the network component of bills increase by 2.9 per cent on average through the 2024–29 regulatory period in nominal terms. This is about $16 a year for a residential customer and $89 per year for a commercial customer on average over the period.

Table 16 Evoenergy revised proposal annual electricity bill impacts (nominal)

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Average
Residential annual electricity bill	$2,267	$2,316	$2,363	$2,353	$2,351	$2,349	
Annual change	–	$49 (2.2%)	$47 (2.0%)	–$10 (-0.4%)	–$2 (-0.1%)	–$2 (-0.1%)	$16
Small business annual electricity bill	$9,572	$9,840	$10,095	$10,041	$10,028	$10,016	
Annual change	–	$268 (2.8%)	$256 (2.6%)	–$54 (-0.5%)	–$13 (-0.1%)	–$12 (-0.1%)	$89

8.5. Regulatory Asset Base

The RAB is the value of the assets that Evoenergy uses to provide standard control services, comprising our distribution and transmission network assets. The AER determines the value of the opening RAB at the commencement of a regulatory period and the method for the indexation of the RAB.

The value of the RAB is a key component used to determine the return of capital and return on capital (regulatory depreciation) building blocks. Our revised proposal accepts the AER's draft decisions in relation to using actual consumer price index (CPI) and forecast CPI to index the RAB and the method of calculating RAB values, noting some components of the methodology will be updated for the AER's final decision.

Table 17 and Table 18 set out Evoenergy's revised proposal RAB for our distribution and transmission network assets, respectively. The combined closing RAB in 2028/29 is 10 per cent higher than the AER's draft decision.

Table 17 Revised proposal RAB for the 2024–29 regulatory period – distribution ($ million, nominal)

	2024/25	2025/26	2026/27	2027/28	2028/29
Opening RAB	938.1	977.0	1,017.5	1,065.0	1,116.7
Capex	87.6	96.7	96.8	103.5	113.1
Inflation indexation on opening RAB	-74.9	-83.5	-77.9	-81.6	-74.2
Less: straight-line depreciation	26.3	27.4	28.5	29.8	31.3
Closing RAB	977.0	1,017.5	1,065.0	1,116.7	1,186.9

Table 18 Revised proposal RAB for the 2024–29 regulatory period – transmission ($ million, nominal)

	2024/25	2025/26	2026/27	2027/28	2028/29
Opening RAB	190.5	199.0	204.4	207.4	218.3
Capex	17.8	16.1	12.8	20.6	8.9
Inflation indexation on opening RAB	-14.6	-16.2	-15.5	-15.4	-14.5
Less: straight-line deprecation	5.3	5.6	5.7	5.8	6.1
Closing RAB	199.0	204.4	207.4	218.3	218.8

8.6. Incentive schemes

AER draft decision

The AER's draft decision was for the following incentive schemes to apply to Evoenergy during the 2024–29 regulatory period:

- Service Target Performance Incentive Scheme (STPIS)
- Capital expenditure Sharing Scheme (CESS);
- Demand Management Incentive Scheme and Innovation Allowance Mechanism (DMIS and DMIAM)

The AER's draft decision was to not apply the efficiency benefit sharing scheme (EBSS) for the 2024–29 regulatory period or the EBSS carryover for 2019–24 because the AER assessed our base year opex as materially inefficient and applied an efficiency adjustment to the forecast.

Revised proposal

Evoenergy's revised proposal is to maintain all the above incentive schemes, including the EBSS, as we consider that our updated 2022–23 base year is efficient.

As detailed in section 8.2, Evoenergy proposes to change the base year used for assessing opeex efficiency. Evoenergy also presents evidence to support adjustments to account for its circumstances, concluding that our base year opex is not materially inefficient. Therefore, we maintain that the EBSS carryover from the 2019–24 regulatory period should be included as a revenue adjustment, and the EBSS should apply for the 2024–29 regulatory period.

As noted in section 8.2, the DMIAM allowance for Evoenergy is insufficient to enable Evoenergy to co-fund community battery projects in the ACT. Investment in community batteries is being encouraged by federal and jurisdictional governments as part of the energy transition journey, with generous government co-funding arrangements in place to promote investment and innovation in this space. Other electricity networks, with larger revenue allowances, receive much higher DMIAM allowances and are therefore more able to participate in community battery co-funding schemes. Participation in the Australian Renewable Energy Agency community battery co-funding requires a minimum $3 million contribution by Evoenergy, more than our entire DMIAM allowance over the 2024–29 period. We heard from our consumers that they support community battery investment to support the energy transition and are concerned that the current approach to calculating Evoenergy's DMIAM level means that the ACT community has limited opportunity to realise the potential benefits of this type of innovation.

Revised incentive scheme revenue adjustments

Evoenergy has applied a total revenue adjustment of $19.8 million resulting from:

- performance under the expenditure incentive schemes applying during the 2019–24 regulatory period;
- a placeholder estimate of the DMIAM for the 2024-29 regulatory period based on the draft decision; and
- the EBSS and CESS carryovers, as outlined below.

EBSS

Table 19 shows the carryover amounts from the EBSS during the 2019–24 regulatory period to apply as revenue adjustment for the 2024–29 regulatory period. The carryover calculations are provided in the EBSS model.

Table 19 EBSS carryover amount 2024–29 ($ million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution	4.1	2.0	2.7	4.5	-	13.3
Transmission	0.8	0.4	0.5	0.8	-	2.5
Total	**4.9**	**2.7**	**3.5**	**5.3**	**-**	**15.8**

CESS

Table 20 shows the updated carryover amounts from the CESS during the 2019–24 regulatory period to apply as revenue adjustment for the 2024–29 regulatory period. The carryover calculations are provided in the CESS model.

Table 20 CESS carryover amount 2024–29 ($million, 2023/24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Distribution	0.7	0.7	0.7	0.7	0.7	**3.4**
Transmission	-0.3	-0.3	-0.3	-0.3	-0.3	-1.4
Total	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**2.0**

Revised STPIS targets

Evoenergy accepts the AER's draft decision on the application of the STPIS. We have provided the 2022–23 STPIS actual performance data in Table 21, together with the updated proposed targets for the unplanned system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI). As we withdrew the proposed Customer Service Incentive Scheme (CSIS), the customer service parameter will be retained in the STPIS.

Table 21 Historical reliability performance

	2018/19	2019/20	2020/21	2021/22	2022/23	Target (average)
Unplanned SAIDI						
Urban	30.932	29.654	32.462	48.632	30.314	34.399
Short Rural	39.805	47.359	58.385	52.912	62.246	52.141
Unplanned SAIFI						
Urban	0.510	0.452	0.472	0.845	0.477	0.551
Short Rural	0.656	0.598	0.737	0.868	0.910	0.754
Customer service						
Telephone answering	78.32%	78.53%	72.52%	68.28%	71.76%	**73.88%**

Note: Consistent with STPIS Version 2.0, the performance results have been adjusted to remove excluded events and Major Event Days.

8.7. Network tariffs

AER draft decision

Evoenergy's proposed TSS for the 2024−29 regulatory period focussed on responding to the challenges and opportunities presented by the accelerating pace of change on the ACT energy network. Evoenergy proposed a number of important tariff reforms to prepare its network tariffs for the increased uptake of EVs, rooftop solar and battery storage on the network.

The AER's draft decision accepted many aspects of Evoenergy's proposed TSS, including the key features of Evoenergy's proposed residential and commercial tariff reforms. The AER accepted Evoenergy's proposal for new, more cost-reflective demand and time-of-use tariffs for residential customers, as well as most elements of Evoenergy's proposed tariffs for grid-scale batteries. While the major elements of Evoenergy's TSS were accepted, the AER's draft decision required some parts of the proposed TSS to be refined to ensure compliance with the pricing principles and other requirements under the Rules. Specifically, the AER draft decision required Evoenergy to:

- consider introducing an opt-in controlled load tariff for the 2024−29 regulatory period to provide incentives for EV owners to charge in ways that minimise impacts on the network;
- more clearly define trigger events for the proposed contingent tariff adjustments;

- remove the proposed contingent tariff adjustment to mandatorily assign EV owners to cost-reflective tariffs; and
- include a basic export level for the grid scale battery tariffs to ensure consistency with the Rules requirements.

Revised proposal

Following Evoenergy's initial TSS proposal, we have continued to engage with the ACT community and energy retailers about our proposed tariffs. This engagement built upon feedback received in public submissions on our initial proposal and the AER's Issues Paper. A common theme in the feedback was the need to strike a balance between keeping network tariffs simple while still signalling the efficient costs of using the electricity network and supporting the uptake of renewable energy technology in the ACT. We heard that if tariffs are too complex, electricity retailers may not adopt them and, even if they are adopted, customers may find it difficult to understand and respond to complex tariffs.

The feedback we received, together with the AER's draft decision on controlled tariffs for EVs, led us to reassess some aspects of our proposed TSS and engage further on tariff options for addressing stakeholder concerns. Through one-on-one meetings with retailers, our Deep Dive Panel sessions, and a consumer survey on controlled load tariffs, we gathered further information and tested our thinking to ensure our revised TSS proposal meets the expectations of stakeholders and consumers. The feedback received during this process is detailed in Appendix 4.1 Tariff Structure Explanatory Statement.

Evoenergy's revised TSS (Attachment 4) includes a number of refinements and changes that respond to stakeholder feedback and reflect new network demand data that has become available since Evoenergy's initial proposal. The revised TSS also addresses the key areas of change identified in the AER's draft decision to improve the alignment of Evoenergy's tariffs with the regulatory pricing principles. Our revised TSS presents a set of tariffs that are easier for customers to understand, simpler for retailers to implement, and provide efficient price signals to support future uses of the ACT distribution network.

The major changes in Evoenergy's revised TSS are detailed in Appendix 4.1 Tariff Structure Explanatory Statement and include:

- **Targeted tariff simplification for residential customers:** We have simplified our proposed new residential time-of-use tariff by removing the inclining block off-peak charge and replacing it with a more familiar, flat off-peak charge structure. This is a direct response to customer and retailer feedback requesting a simple time-of-use tariff option as an alternative to the more advanced residential demand tariff.
- **Removal of the proposed residential export tariff:** We are no longer proposing to introduce a residential export tariff in our revised TSS for the 2024−29 regulatory period. Instead, we will utilise the proposed 'solar soak' charges to reward customers with a lower price for energy used at times when solar exports are typically high. Solar soak charges provide customers with a simpler and more gradual introduction to export-based price signals, while still managing the costs of two-way flows on the ACT network. The removal of the export tariff responds to mixed customer views about the fairness of export charges, the preference for simple network tariffs, and retailer concerns about implementation complexity and cost.
- **Investigations into tariff options to support residential EV recharging:** We have undertaken research and engagement to understand better customers' EV charging patterns, responsiveness to price signals, and preferences for future network tariffs. For the 2024−29 regulatory period, Evoenergy will continue to offer its existing controlled load tariffs to EV owners on an opt-in basis to encourage charging outside of peak times. We will also investigate 'flexible load' tariff options that could be used in the future to dynamically manage EV recharging while giving customers flexibility and control.

- **Updates to peak charging windows**: The latest data on network demand shows the accelerating pace of electrification in the ACT, including the growing impacts of customers transitioning from gas to electricity. We have adjusted the charging windows on our proposed residential tariffs to better reflect the anticipated use of the network in the 2024−29 regulatory period. This includes extending the evening peak by one hour on the new residential tariffs (now, 5pm–9pm AEST); and adding a morning peak period to the proposed time-of-use tariff (7am–9am AEST).
- **New individually calculated tariffs for customers connecting at HV:** For the first time, HV customers are seeking to connect to Evoenergy's sub-transmission network, where Evoenergy's existing HV tariffs would not be cost-reflective. For these customers, we are proposing individually calculated tariffs that reflect the unique connection arrangements and costs for connections at 66 kV and above.
- **Other changes to address the requirements of the AER's draft decision:** We propose to remove the contingent tariff adjustment mechanism from the revised TSS because the proposed tariff adjustments have been addressed through other parts of the revised TSS (e.g. extended peak periods on the new residential tariffs). In line with AER's draft decision, Evoenergy's revised TSS includes a basic export level for the export charge on the proposed grid-scale battery tariff (for batteries located in residential areas).

Removal of the residential export tariff

As noted above, we do not propose to introduce export charges for residential customers during the 2024−29 period. Evoenergy's revised TSS departs from the approach in the initial TSS, which included a proposed residential export tariff to prepare the ACT network tariff structure for the anticipated future increase in export costs. The removal of the residential export tariff reflects new information and stakeholder feedback received on Evoenergy's proposed TSS, which is explained in sections 5 and 9 of its TSES. This includes:

- Feedback from customers indicating a strong preference for simple tariffs and concerns about the mixed signals sent by export charges in relation to the uptake of CER on the network.
- Feedback from retailers, which included that Evoenergy's initially proposed export tariff was difficult to implement, and there was a low likelihood it would be widely adopted in retail tariffs offered to ACT customers.
- Feedback concerning the significant costs[16] and implementation complexity of residential export tariffs within Evoenergy's billing system, including the finding that implementation of a residential export tariff by 1 July 2024 is not possible based on current market availability and constrained resourcing.

We have carefully considered the stakeholder feedback, along with the high costs and complexity of implementing export tariffs, and have weighed this against the relatively small network impacts expected from small-scale residential solar in the 2024−29 regulatory period. Evoenergy notes that additional investment will be required in its billing system to implement a residential export tariff, which includes the development of new, custom capabilities that are not currently available to us. In the revised TSS, Evoenergy has concluded that the pre-emptive introduction of residential export tariffs in 2024−29 does not reflect prudent and efficient investment that is in customers' best interests at this time.

Instead, Evoenergy proposes a more gradual, measured, and responsible transition pathway to begin introducing residential customers to export-related pricing concepts in the 2024−29 regulatory period. This will be achieved through the 'solar soak' charges on Evoenergy's proposed residential time-of-use and demand tariffs. These charges reward customers with a lower price for 'soaking up' energy between 11am–3pm AEST when solar exports are typically highest. Solar soak charges have the potential to reduce export-related costs on the network while also being simple for customers to

[16] The costs of implementing the tariff would have been incurred in the 2019−24 regulatory period, and do not form part of Evoenergy's expenditure forecasts for the 2024−29 regulatory period.

understand and simple for retailers to implement in retail tariffs. Importantly, the proposed solar soak charges provide a much stronger price incentive, and are expected to cover a much larger number of customers, than the initially proposed export tariff.

Under the proposed gradual transition, Evoenergy will fully explore the role that solar soak charges can play in managing exports on the network before considering residential export tariffs again in future periods. This will provide more time for customers and retailers to become familiar with Evoenergy's other residential tariff reforms (including the new residential demand and time-of-use tariffs), and avoids introducing additional tariff complexity at a time when it is not yet required.

8.8. Alternative control services

Metering

AER draft decision

For its draft decision, the AER substituted Evoenergy's proposed prices for type 5 (interval) and type 6 (accumulation) metering services (legacy metering services). The AER made draft decisions to:

- update Evoenergy's base year metering opex and revise the trend component of the forecast to reflect a metering volume forecast consistent with the AEMC's 2030 roll-out target;
- accept Evoenergy's proposal to accelerate the depreciation of the metering services RAB, but brought forward the depreciation schedule to the end of the 2024–29 regulatory period;
- revise Evoenergy's annual revenue requirement, which required updating to reflect changes to the return on capital, regulatory depreciation and opex building blocks; and
- not accept Evoenergy's price cap calculation for legacy metering services and substituted its price cap calculation to recover costs through a fixed fee charged to a wider customer base.

In its draft decision, the AER provided information about recent changes affecting metering services, including the outcome of a review of the regulatory framework for metering services conducted by the AEMC.

As part of the draft decision, the AER discussed the appropriate form of control for metering services. It considered that there had been a 'material change in circumstances' since its final Framework and Approach paper where legacy metering services were classified as ACS. The AER considered the AEMC's requirement to replace all legacy meters by 2030, which meant that it would be appropriate to reclassify legacy metering services as a SCS.

Revised proposal

Evoenergy's revised proposal:

- Updates our base year operating expenditure forecast with actual data for 2022/23 ($2.2 million).
- Accepts most components of the AER's method of forecasting operating expenditure, including:
  - using the base step trend method;
  - applying an 'economies of scale' factor of 60 per cent to the trend component of the forecast; and
  - accepting the AER's draft decision split between fixed (35 per cent) and variable costs (65 per cent).
- Updates the metering volume forecast by revising the 2022/23 estimate to an actual number.

- Does not accept the AER's approach to apply a logarithmic function to metering volume change and instead applies a simple rate of change.
- Maintains the ACS classification and price cap form of control.

Further details of Evoenergy's revised proposal for metering services are provided in Attachment 5 Alternative Control Services.

Ancillary network services

AER draft decision

The AER's draft decision was to:

- Maintain the price cap form of control for ANS, including setting a schedule of price caps for fee-based services and maximum labour rates for quoted services.
- Accept Evoenergy's proposal to remove 18 fee-based services and add eight new services.[17]
- Accept 12 of Evoenergy's proposed fee-based and quoted services labour rates and substitute five with the AER's benchmark.
- Not accept the application of a margin allowance of six per cent, outside of the overhead rate for fee-based services.
- Not accept the proposed crew size of three to perform certain network connection fee-based services.
- Accept that the approach to contractor costs were reasonable but requested that sufficient evidence is provided to support the proposed costs.
- Request further information to demonstrate the material costs to provide network connection services are efficient.

Revised proposal

Evoenergy accepts the AER's draft decision in relation to:

- the form of control for ANS;
- fee-based quoted services labour rates;
- the margin allowance that the AER considers is already accounted for in the overhead rate; and
- the approach to deriving labour price growth forecasts using revised assumptions.

Evoenergy does not accept the AER's draft decision to:

- maintain the amount of labour to perform network connection fee-based services; and
- not include proposed material and contractor costs for all network connection fee-based services including supply abolishment and removal.

We provide further information in Attachment 5 Alternative control services to explain why our labour allocation and inclusion of material and contractor costs are prudent and efficient. We have also proposed an additional service: Re-energise premises – site visit only. The service is required to recover costs when Evoenergy staff attend a customer site to re-energise or de-energise a premises but cannot access the site to perform the service. The revised proposal schedule of ANS rates is provided in our indicative pricing schedule and ANS cost build-up model.

[17] Most of the services were removed due to low usage or consolidated into other services.

Glossary

	Alternative control services
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANS	Ancillary Network Services
Augex	Augmentation expenditure
Capex	Capital expenditure
CCP26	Consumer Challenge Panel 26
CER	Consumer energy resources
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer price index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	Customer Service Incentive Scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DRC	Debt raising cost
EBSS	Efficiency Benefit Sharing Scheme
ECRC	Energy Consumer Reference Council
EN24	Electricity Distribution Determination 2024-29
ESOO	Electricity Statement of Opportunities
EV(s)	Electric vehicle(s)
HV	High voltage
ICT	Information and communications technology
IEP	Integrated Energy Plan
ISP	Integrated System Plan
LV	Low voltage
MW	Megawatt
NEO	National Electricity Objective
NER / the Rules	National Electricity Rules
OEF	Operating environment factor
Opex	Operating expenditure
POE	Probability of exceedance
RAB	Regulatory Asset Base
Repex	Replacement expenditure
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index

SAIFI	System Average Interruption Frequency Index
SCS	Standard control services
SOCI	Security of Critical Infrastructure Act
STPIS	Service Target Performance Incentive Scheme
SG	Superannuation Guarantee
tCO_2e	Tonnes of carbon dioxide equivalent
TSS	Tariff structure statement