Ergon Energy Network Regulatory Proposal

2025-30

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Part of Energy Queensland

Contact details

Manager Economic Regulation
Email: RDP2025Connect@energyq.com.au

PO Box 1090, Townsville QLD 4810
Level 6, 420 Flinders Street, Townsville QLD 4810
www.energyq.com.au

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ACKNOWLEDGEMENT

Ergon Energy Network acknowledges the Traditional Custodians of the land on which our distribution network is located, and we recognise their continuing connection to land, waters, and community.

We pay our respects to Elders past and present for they hold the memories, the traditions, the culture and hopes of Aboriginal and Torres Strait Islander peoples in Queensland. We extend that respect to all Aboriginal and Torres Strait Islander people today.

Ergon Energy Network is committed to continuing to work in partnership with First Nations people to ensure we deliver clean, reliable and smart energy supply to communities in regional Queensland in the most affordable way.

ABOUT THIS REGULATORY PROPOSAL

Ergon Energy Corporation Limited (Ergon Energy Network) is a subsidiary company of Energy Queensland Limited (Energy Queensland), a Queensland Government Owned Corporation, and is the electricity distribution network service provider (DNSP) for regional Queensland. We own, operate, and maintain the 'poles and wires' that deliver power to 761,000 homes and businesses from the State's expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

As part of Energy Queensland, Ergon Energy Network is committed to energising Queensland communities by working together towards empowering an 'Electric Life' for our customers, and to transforming the energy system to meet future needs.

To ensure Ergon Energy Network manages the distribution network in regional Queensland efficiently, we are regulated under the National Electricity Rules (NER) by a national regulator, the Australian Energy Regulator (AER). Every five years, Ergon Energy Network is required to submit a Regulatory Proposal to the AER setting out the amount of funding required to build, operate, and maintain the electricity distribution network in regional Queensland and the revenue we intend to collect from our customers through distribution charges.[1] Ergon Energy Network's next five-year regulatory control period commences on 1 July 2025 and ends on 30 June 2030 (the 2025-30 regulatory control period).

Ergon Energy Network's Regulatory Proposal includes this document, setting out our regulated distribution services and the revenue and prices associated with them for the 2025-30 regulatory control period, and is accompanied by a plain-language overview of our proposal and a range of supporting documentation, including our proposed Tariff Structure Statement.

This Regulatory Proposal is structured as follows:

- **Executive Summary** - provides a high-level summary of our Regulatory Proposal
- **Chapter 1: Context for our Proposal** - provides background information for context, including our role in energising regional Queensland communities, how we have delivered for customers during the 2020-25 regulatory control period and our operating environment
- **Chapter 2: Customer and Stakeholder Engagement** - outlines how we have engaged with customers and stakeholders and provides a summary of what we have heard and how this has influenced our Regulatory Proposal
- **Chapter 3: Investment Priorities** - sets out Ergon Energy Network's investment priorities for 2025 and beyond
- **Chapter 4: Demand, Energy Delivered and Customer Forecasts** - details the base case energy demand forecasts developed for the 2025-30 regulatory control period
- **Chapter 5: Capital Expenditure** - sets out our capital expenditure (capex) plans, our forecasting approach and how we will be delivering for customers
- **Chapter 6: Operating Expenditure** - sets out our operating expenditure (opex) plans, our forecasting approach and how we will be delivering for customers

[1] Clause 6.8.2(c) of the NER sets out the information that must be included in a Regulatory Proposal.

- **Chapter 7: Incentive Schemes** - covers the application of incentive schemes
- **Chapter 8: Annual Revenue Requirement** - sets out the proposed revenue to enable us to continue to build and maintain a safe and reliable network
- **Chapter 9: Network Tariffs and Pricing** - provides an overview of our proposed network tariff structure and how our tariffs were developed
- **Chapter 10: Metering** - explains our proposal to change the charging arrangements for legacy metering services
- **Chapter 11: Alternative Control Services** - outlines our proposals for public lighting and other alternative control services (ACS), and
- **Chapter 12: Other Regulatory Matters** - provides information on several related matters, including classification of services, control mechanisms, negotiating framework, pass through events and contingent projects, and addresses our approach to confidentiality and assurance and certification requirements.

Our Regulatory Proposal has been informed by the views and preferences of our customers and stakeholders obtained from business-as-usual and targeted customer engagement activities. This includes feedback in response to our Draft Plan published in September 2023, which outlined our initial insights from customer and stakeholder engagement and our proposed investment plans for the 2025-30 regulatory control period.

As set out in Figure 1 below, our Regulatory Proposal must be submitted to the AER by 31 January 2024. The AER will assess our Regulatory Proposal and consult with interested parties before setting the maximum revenue Ergon Energy Network is allowed to recover from customers for their use of the network over the next five-year regulatory control period commencing 1 July 2025. This revenue will form the distribution network component of customers' retail electricity bills. We encourage our communities and customers to make submissions to the AER as part of its consultation process on our Regulatory Proposal.

In the meantime, we will continue to engage with our customers and other stakeholders, including through our online engagement hub, Talking Energy, www.talkingenergy.com.au. Questions can also be directed to us by emailing RDP2025Connect@energyq.com.au.

Figure 1: Next steps

MESSAGE FROM OUR CHAIR AND CEO

In developing expenditure plans that are reflective of customer preferences both now and into the future, we have sought to strike the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way.

Ergon Energy Network is operating in a time of change and uncertainty. Australia's energy market is undergoing a period of rapid and profound transformation in response to technological advances, climate change, the shift to renewable energy sources and evolving customer expectations. With the transition to a clean energy future and the reshaping of Australia's energy market, our role in managing the network is changing and the ways our customers use and interact with our network are also shifting. To enable our customers and communities to leverage the benefits that flow from the transition to more renewables and smart technologies, we will require a more intelligent, integrated and dynamic network supported by innovation, technology, and policy reform.

At the same time, our operating environment is characterised by unprecedented economic and environmental challenges and opportunities. While the energy transformation is expected to drive investment in the Queensland economy, we are conscious that high inflation and rising interest rates have created cost-of-living and cost-of-business pressures for our customers. The communities we serve are also increasingly susceptible to the impacts of climate change and other disruptive events. As an essential part of modern life, it is important that we do all that we can to provide an affordable, reliable and resilient electricity supply to 'keep the lights on' for regional Queensland's households and businesses.

Similarly, as a major employer in regional Queensland, we are proud to be playing an important role in the energy market transformation by supporting the shift to renewable energy across the State, which will not only deliver clean energy for households and businesses but also generate new jobs and opportunities for workers and local communities. We will play our part by supporting the deep electrification of homes and businesses that brings benefits to all customers through a measured, sustained approach to the transformation.

This Regulatory Proposal, setting out the funding required to build, operate, and maintain the electricity distribution network in regional Queensland for the five-year regulatory control period, has been shaped through conversations with customers and other stakeholders. Not surprisingly, our customers have told us that affordability of electricity, from both a cost-of-living and business competitiveness perspective, is their primary concern. With this in mind, we have focused on spending only what is prudent and efficient to meet the energy needs of regional Queensland so that our customers pay no more than is necessary for their electricity supply. We have also identified opportunities for customers to reduce the price they pay for electricity through reform of our network tariff structures.

Executive Summary

While keeping affordability front of mind, our customers have also been clear that we should not compromise our distribution electricity supply or our customer service standards. Consequently, our proposed five-year investment plans are aimed at ensuring our network can enable a higher penetration of renewables and meeting the expected increase in future demand that will flow from economic, jobs and population growth. They will enhance our ability to prepare for and recover from the impacts of climate change and other disruptive events, and continue to deliver our electricity services cost-effectively and to a high standard.

In developing expenditure plans that are reflective of customer needs and expectations, both now and into the future, we have sought to strike the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way. Due to the application of the Queensland Government Uniform Tariff Policy and the Community Service Obligation of around $600 million per annum, almost all Ergon Energy Network customers will see the equivalent Energex price. This means that, on average, the increase in distribution network charges for households will be limited to an average of $34, or 5 per cent, in each year of the 2025-30 regulatory control period.

We truly value the feedback we have received from our customers to date and invite you to have your say about the future of Ergon Energy Network and the energy needs of regional Queenslanders through the AER’s consultation process.

Sarah Zeljko
Chair
Energy Queensland Board

Peter Scott
Chief Executive Officer
Energy Queensland

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EXECUTIVE SUMMARY

This Regulatory Proposal sets out Ergon Energy Network's proposed revenue requirements for the provision of electricity distribution services in the 2025-30 regulatory control period.

Every five years Ergon Energy Network is required to submit a Regulatory Proposal and Tariff Structure Statement setting out, amongst other things, our proposed expenditure, revenue allowance and network tariff structures to the AER. The AER will assess our Regulatory Proposal and set the efficient revenue and prices that we can recover from customers over the forthcoming regulatory control period. The AER's assessment will include consumer engagement to assist in its decision-making.

Ergon Energy Network recognises that our customers and other stakeholders are central to our plans. Consequently, we have undertaken a targeted engagement program that leverages off our existing engagement activities to inform the development of our Regulatory Proposal. In September 2023 we published a Draft Plan which formed a key part of our conversations with customers and stakeholders. Feedback provided in response to our Draft Plan as well as through other business-as-usual and targeted engagement activities has been used to shape Ergon Energy Network's Regulatory Proposal.

Our Regulatory Proposal is summarised below. (All financial values in this Regulatory Proposal are in real 2024-25 dollars, unless stated otherwise.)

Chapter 1: Context for our Proposal

Ergon Energy Network builds, operates and maintains the electricity distribution network for regional Queensland. We provide a range of distribution services to our customers and communities, including connecting customers to our network, maintaining the network to ensure a safe, secure and reliable supply of electricity for our customers, reading and testing meters, and providing public lighting.

Ergon Energy Network performs an important role in energising regional Queensland communities. How we build, operate, and maintain our network is driven by the unique and varied expectations and needs of the region's residents, businesses, and communities. The vast size of Ergon Energy Network's distribution area and the geographically dispersed nature of the population means that our network needs to cover long distances and be sufficiently resilient to safely and reliably support our customers' domestic, commercial, and industrial needs and preferences now and into the future. Along with strong population and economic growth in our service areas, the demand for power is increasing.

During the current 2020-25 regulatory control period we have been working hard to deliver on our customer commitments. Over the past three years (2020-21 to 2022-23), we have invested in the safety, reliability and security of our network and solutions to support greater uptake of new and emerging technologies, including:

- $1,375 million on operating and maintaining our network, including inspecting, maintaining and repairing network assets, controlling vegetation growth, undertaking fault and emergency repairs and restoring supply
- $1,818 million on renewing, reinforcing and building the network to supply power across our distribution area, integrating distributed energy resources and connecting new homes and businesses, and
- $411 million on supporting the business to deliver a secure and reliable electricity supply to customers, through investment in ICT, buildings, fleet, tools and equipment.

At the same time, we have continually looked for ways to make electricity more affordable and opportunities to provide better outcomes for all customers.

Our key priorities and the development of our expenditure, revenue and tariff plans for the next regulatory control period are strongly influenced by the environment in which we operate. We are preparing our expenditure plans at a time when the challenges and opportunities have never been greater or more complex. The operating environment factors we have considered in developing our plans not only include the energy transformation currently under way, but also increasingly challenging climate and environmental conditions, Queensland's expected economic, population and jobs growth, and the cost-of-living pressures impacting our customers.

Further information on Ergon Energy Network, our operating environment and what we have delivered for customers during the current 2020-25 regulatory control period is provided in Chapter 1.

Chapter 2: Customer and Stakeholder Engagement

To ensure we are meeting the diverse needs of our customers and stakeholders we engage regularly with them to obtain insights and feedback on their needs, expectations, and the issues that matter most to them. In addition to our business-as-usual engagement, we have undertaken targeted engagement specific to the development of our Regulatory Proposal, including publication of a Draft Plan for public consultation. Insights from this engagement have been used to inform our Regulatory Proposal.

In developing our engagement strategy we partnered with our customers and stakeholders to identify overarching themes to guide our engagement discussions. The themes developed were based on the energy challenges and issues that our customers and stakeholders told us are important to them. These overarching themes are: **Affordable**, **Clean**, **Reliable** and **Smart** (refer to Figure 2). As an essential service provider, **Customer Service Excellence**, was also included, with it being at the centre of all our activities.

Figure 2: Engagement Themes

Our targeted engagement focused on those areas of our plans where customers expressed an interest and can have the most influence. As a result, and in consultation with our Reset Reference Group (RRG), we primarily engaged on network tariffs and customer service. In addition, we ran tailored consultation on topics such as public lighting, distributed energy resources (DER) and our property and fleet strategies, with insights specific to different topics being referenced across our Regulatory Proposal.

We have continued to hear the following key messages throughout our engagement activities:

- safety should never be compromised
- electricity affordability is a concern for many customers – both from a cost-of-living and a business competitiveness perspective
- our customers want clear and concise information and access to energy usage data to help them make informed choices around their energy solutions, with both pricing and non-pricing options available to manage energy costs
- there is significant interest in renewables and DER, with growing concerns about climate change fuelling customer and community expectations around the transition to a low carbon economy
- good customer service is expected, with transparency in customer service performance seen as essential to giving customers confidence in the services delivered
- our customers and communities value how we go about keeping the lights on, especially our response to severe weather events and other natural disasters, and
- the economic environment continues to bring 'energy inclusion and customer vulnerability' and 'economic resilience and jobs' to the foreground.

The key priorities that have driven our investment plans for the 2025-30 regulatory control period have been informed by the feedback customers have provided as part of both our tailored and business-as-usual engagement activities.

In Chapter 2, we talk further about how we have engaged with our customers, the feedback we have received from them, and how we have taken their insights, needs and preferences into account when developing our future plans.

Chapter 3: Investment Priorities for 2025-30

Our customers have made it clear that affordability of electricity is their paramount concern. However, our customers have also told us that they expect us to maintain reliability, resilience, service and safety. These priorities are reflected in our proposed five-year investment plans, which are aimed at supporting a higher penetration of renewables and meeting the increased demand that will flow from economic, jobs and population growth.

As discussed in Chapter 3, there are four key priorities that are driving our investment plans for the 2025-30 regulatory control period. They are set out in Figure 3.

Figure 3: Our four investment priorities

Investment priority 1: Deliver electricity services in the most efficient and affordable way

In delivering our investment plans, we will aim to invest only what is necessary to meet the energy needs of regional Queensland, and in so doing minimise price increases for our customers. However, we do not want to be in a position in the future where we place the burden to pay on the next generation of customers because we have not acted today. Therefore, we must strike the right balance between investing into the network to provide clean, reliable and smart electricity to homes and businesses and addressing customers' affordability concerns. To that end, we are committed to providing cost-effective and efficient services that allow us to keep pace with the energy transition and deliver affordable electricity supply to our customers.

To minimise bill impacts, we will spend only what is prudent and efficient to meet customer needs now and into the future. As previously discussed in our Draft Plan, we will apply a 1 per cent productivity factor to both opex and capitalised overheads to drive efficiency improvements and cost savings in how we deliver electricity to our customers and self-fund the non-network information and communications technology (ICT) capex above the AER forecast for the past five years.

Investment priority 2: Ensure the safety and reliability of our ageing network

Network assets in parts of our distribution network in regional Queensland are ageing and at risk of failure. Replacement or reinforcement of older assets like poles, powerlines and substations is critical to ensuring we meet the safety and reliability expectations of our customers and communities. We have invested in these essential works in recent years and plan to continue that investment during the next regulatory control period.

Investment priority 3: Provide a well-integrated and resilient electricity network to meet future needs

Queensland's energy system is rapidly transforming from a one-way flow of electricity to customers from large, typically coal-fired, generators to a bi-directional flow that includes increasing volumes of both large and small-scale renewable energy sources powering our homes and businesses.

In line with the transition to a clean energy future and the expected growth in regional Queensland's economy and population, our distribution network will need to provide the electricity infrastructure to support more household and business connections, including renewable energy sources such as wind and solar. We will therefore invest in upgrading the network to meet forecast demand and improve its resilience to the impacts of climate change and increased exposure to cyber and physical infrastructure security risks. We will also transform the network into a more intelligent and dynamic grid to manage and enable more DER to be connected at lower cost. At the same time, we will explore opportunities to deploy stand-alone power systems (SAPS) where they are a more cost-effective and efficient alternative to building traditional poles and wires.

Investment priority 4: Facilitate customer opportunities in the transition to renewable energies

The transition to a net zero emissions future and the increasing solar generation from rooftops and large solar farms during daylight hours has meant that Ergon Energy Network must develop strategies to manage the challenge of low energy demand during the day, which can cause power quality issues that can be harmful to customer appliances as well as the network. Consequently, we are proposing to deliver integrated solutions that will help make the best use of generation and deliver benefits and opportunities for both our customers and our network.

Solutions include changing network tariffs to encourage greater energy use during periods of high solar export, expanding our demand management program, and dynamic operation of the network to manage DER more efficiently and limit the need for network investment. We will also look at opportunities for customers who do not have access to DER so that they too will benefit from the transition to renewables and save on their electricity bills. Further, throughout the five-year period we will continue to collaborate with our customers to ensure that their views are heard and their needs are being met, as well as advocate for industry-wide solutions to provide better outcomes for all customers.

Chapter 4: Demand, Energy Delivered and Customer Forecasts

Chapter 4 details the base case energy demand forecasts developed by Ergon Energy Network for the 2025-30 regulatory control period. In summary, we expect that for the five-year period:

- continued growth in the network will result in system peak demand rising by an average of 1 per cent annually
- the increasing penetration of rooftop solar will cause minimum demand to fall by an average of 100 megawatts (MW) annually
- energy delivered will decrease by an average of 0.2 per cent annually
- annual average growth in customer numbers will be around 0.8 per cent in line with expected population growth in Queensland
- electric vehicle volumes will increase from between 41,000 units and 118,000 units by 2030 (depending on the rate of uptake) as there is greater choice and cost parity with conventional vehicles
- solar photovoltaic (PV) uptake is likely to remain strong and could grow by up to 10.3 per cent annually, and
- battery energy storage systems will potentially increase by 35.8 per cent annually as they become more economically viable.

Chapter 5: Capital Expenditure

Our customers and communities expect Ergon Energy Network to maintain the reliability, resilience and safety of our network, while meeting the needs of a growing economy and population and facilitating opportunities in the renewable energies transition.

Many of our regions are growing and the demand for power is increasing, particularly in the larger centres. We must invest in our distribution network to ensure there is enough capacity to supply every household and business on the days when electricity demand is at its maximum, no matter where they are located across our distribution area, and have enough capacity to accept the growing distributed solar energy that our customers export each day. We must also continue to invest in the safety and performance of our network and be ready to respond to emergencies and major weather events. At the same time, in response to customer concerns about affordability, we are focused on driving down the controllable aspects of our capex program without compromising the safety or reliability of the network.

Our capex plans for the 2025-30 regulatory control period are set out in Chapter 5. This expenditure relates to the investment we need to make to build and maintain our network assets, such as poles, wires, and transformers, and connect new customers. It also relates to the investment in assets that support the network, including vehicles, depots, and ICT.

Our capex plans for the five-year period are summarised below.

Historical Spend

From 2019-20 onwards our network capex has increased, primarily driven by our investment in refurbishment and replacement works to address the performance challenges of an ageing network and meet community safety and reliability expectations. We recognise that it is unprecedented to significantly exceed the AER's capex forecast. However, we will provide the AER with information to demonstrate that the costs relating to our refurbishment and replacement works are prudent and efficient; and the investments will provide long-term benefits to customers. While this additional capex will increase Ergon Energy Network's regulatory asset base (RAB), and associated revenues, due to the application of the Queensland Government's Uniform Tariff Policy, households and small business customers will be protected from any price impacts from this increased capex.

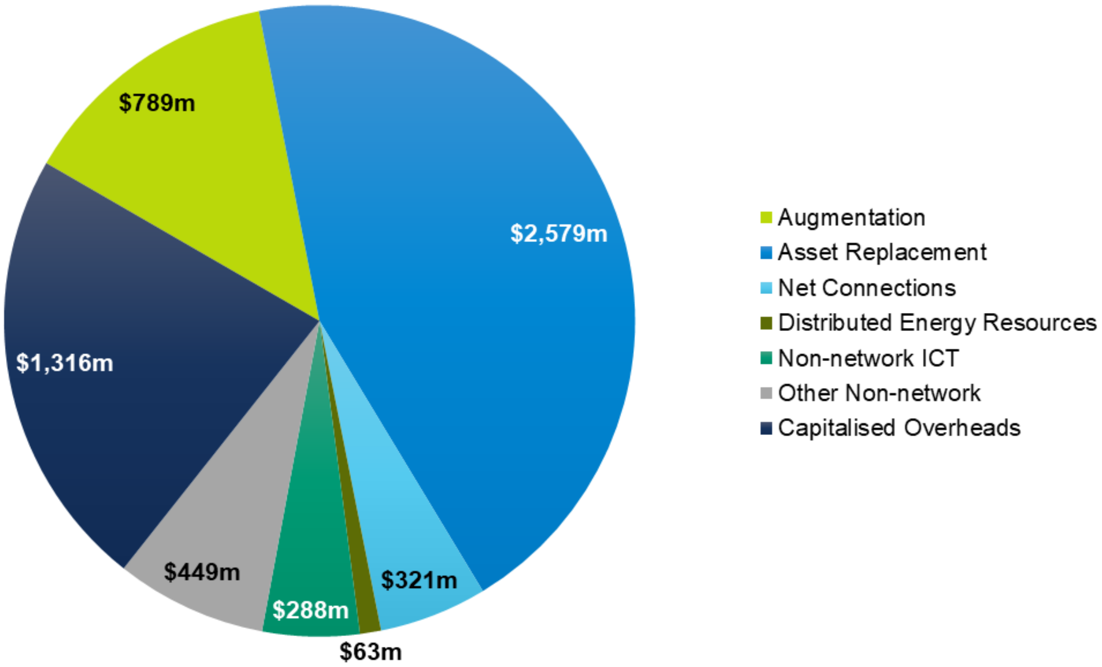
Other drivers of our historical capex are non-network ICT, capitalised overheads and property, which are also discussed in Chapter 5.

Forecast Spend

We have forecast that our capex will increase by 20 per cent to $5,805 million in the 2025-30 regulatory control period. Aligned to our investment priorities, this increase is due to the need to invest in replacing or upgrading ageing infrastructure, reinforcing areas of the network where electricity demand is increasing and improving the reliability of electricity supply in regional areas. As our workforce grows to deliver this important infrastructure, our support costs also increase.

As illustrated in Figure 4, approximately $2,579 million (44 per cent) of our forecast capex program is to maintain the safety and reliability of our ageing network, $789 million (14 per cent) is to reinforce areas of the network experiencing growth, reliability or power quality issues, $63 million (1 per cent) is to integrate DER into the network and $321 million (6 per cent) is for connecting new customers or upgrading existing connections (after taking into account capital contributions from customers). The remainder is comprised of $288 million (5 per cent) for non-network ICT and $449 million (8 per cent) for property, fleet, and tools and equipment required to undertake our capital works program and $1,316 million (23 per cent) for other costs we incur to support the delivery of our network services that cannot be directly attributable to a service.

Figure 4: Capex Forecast 2025-30 by Category



Chapter 6: Operating Expenditure

Customers have told us that, although affordability of electricity supply is their primary concern, they expect Ergon Energy Network to keep our network safe, reliable and secure and to keep the lights on for their homes and businesses. They rely on us to be vigilant with respect to the safety of our network and particularly value how we respond to severe weather events and natural disasters to ensure power supply is restored to communities as quickly as possible. Ergon Energy Network's opex is therefore focused on ensuring that we continue to operate and maintain our network to meet the everyday performance and service expectations of our customers and communities in the most affordable way.

Chapter 6 sets out Ergon Energy Network's initial opex plans for the 2025-30 regulatory control period. This expenditure relates to the day-to-day costs required to operate and maintain our network assets and includes activities such as: inspection, maintenance and repair of network assets; control of vegetation growth; fault and emergency repairs and supply restoration; and customer service and corporate support activities.

Our opex is influenced by the unique environment in which we work, which is characterised by a widely dispersed population over a large geographic area. The climate of regional Queensland varies from cooler temperatures in the Darling Downs in the south of the State to high temperatures and humidity across the eastern seaboard and out to western Queensland. The region also has a high exposure to cyclones, severe storms, flooding and bushfires. The harsh environment of regional Queensland has a significant impact on the life of our network assets, vehicles, tools and equipment, and the safety and reliability of the network.

Applying the base-step-trend forecast approach, we have forecast that our opex will be $2,379 million for the 2025-30 regulatory control period.

Chapter 7: Incentive Schemes

Several incentive schemes apply to regulated electricity network businesses across Australia. The purpose of these schemes is to incentivise networks like Ergon Energy Network to run an efficient business so that customers pay no more than is necessary for the services they require and to ensure the right levels of service are being provided to customers for those they most value. As such, we continue to support the application of incentive schemes.

We are proposing that the existing AER incentive schemes designed to encourage network businesses to be more efficient, maintain or improve service performance, and pursue alternative non-network solutions will continue to apply to Ergon Energy Network in the 2025-30 regulatory control period.

As discussed in Chapter 7, we sought feedback from customers on whether the new Customer Service Incentive Scheme (CSIS), designed to incentivise distributors to maintain and improve the quality of their customer service, should also be applied. The overwhelming sentiment from our Voice of the Customer Panel process was that good customer service should be part of every business and it was expected that we would provide this regardless of any incentive scheme. Their recommendation was that the CSIS should not apply to Ergon Energy Network. We accept the feedback from customers and propose to not apply the CSIS in the 2025-30 regulatory control period.

While our consultation was primarily focused on the application of the CSIS, given our customers' strong views that we should not be rewarded for good customer service, we are also proposing that the customer service component of the Service Target Performance Incentive Scheme (STPIS) should not apply.

In addition, although we support the Export Service Incentive Scheme (ESIS), we are not proposing that it should apply during the 2025-30 regulatory control period as we do not currently have robust data to enable us to design and consult on the scheme prior to 1 July 2025.

Chapter 8: Annual Revenue Requirement

Ergon Energy Network's proposed total revenue for the 2025-30 regulatory control period to enable us to continue to build and maintain a safe and reliable network is $7,819 million (unsmoothed).

Our revenue requirement is driven by:

- a significant increase in our forecast return on capital (or financing costs) mainly due to factors outside our control, such as:
    - interest rates rising sharply since our last distribution determination
    - higher than forecast inflation during the current regulatory control period
- an increase in our RAB because of higher capex in the current and next regulatory control periods
- an increase in our forecast opex requirements, and
- an increase in our tax allowances.

The revenue increases are reduced by penalties we forecast to incur under the AER's capex and opex incentive schemes.

Given our proposed plans and revenues, in nominal terms, we estimate that total annual network charges (inclusive of transmission charges and jurisdictional schemes) would increase by an average of:

- $66, or 6 per cent, annually for residential customers
- $146, or 6.8 per cent, annually for small business customers, and
- $4,342, or 7.1 per cent, annually for a large business connected on the low voltage network.[2]

However, due to the application of the Queensland Government's Uniform Tariff Policy and the Community Service Obligation payment of around $600 million per annum, 99 per cent of customers will see the equivalent Energex price. Therefore, on average, the increase for householders will be $34 or 5 per cent.

Chapter 8 sets out the building block requirements used to determine our total allowed revenue.

Chapter 9: Network Tariffs and Pricing

Customer input and preferences on network tariffs has been a key focus of our engagement due to the significance of potential changes to network tariffs and the likely impacts from those changes.

We know that electricity affordability is a key concern for many of our customers due to increases in both the cost-of-living and in doing business. Customers have also told us that, with respect to network tariffs, they are looking for simplicity, savings, value and choice, that rewards them for their role in the energy transition.

Engagement on our Draft Plan focused on five broad themes related to network tariffs: strengthening the peak price signal; updating time of use (ToU) windows; transitioning to two-way pricing; updating load control tariffs; and streamlining existing tariffs.

In line with feedback from our customers, we are seeking to:

- strengthen the peak price signal to ensure residential and small business network tariffs better reflect the costs when demand on our network is highest and assist customers as they make choices around emerging technology
- update our time of use (ToU) charging windows to provide customers with more accurate price signals about the costs required to service demand at different times of the day and enable customers the opportunity to reduce their energy bills without reducing their total energy usage
- transition to two-way export pricing for low voltage customers by encouraging exports during peak demand periods and self-consumption during the day that will reduce future network costs, and greater customer participation in energy management and energy management tools
- update our controlled load tariffs to ensure they continue to remain relevant to customers and offer a greater choice of options to achieve a lower network bill, and
- streamline our existing tariff offerings to make them easier for customers to understand.

In Chapter 9 we provide a summary of proposed tariffs for the 2025-30 regulatory control period and feedback from engagement with our customers which has informed their development.

[2] The price impacts factor in transmission charges from Powerlink that are forecast to increase by inflation and the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. For forecast inflation, we have used a forecast of 2.75 per cent based on the AER's methodology set out in the Post Tax Revenue Model.

Chapter 10: Metering

Our residential and small business customers who do not yet have a smart meter installed continue to receive metering services from Ergon Energy Network. The costs of providing legacy metering services associated with network-installed basic accumulation meters have historically been recovered from those customers receiving the service (i.e. user-pays). However, given that the number of legacy meters will decrease over time as more smart meters are installed, the AER has provided guidance that the costs of providing metering services for those remaining meters should more appropriately be recovered from all customers through our network charges as a standard control service (SCS). This will reduce the burden on customers who have yet to receive a smart meter and ensure the transition to smart metering is fair and equitable.

We sought customer views on the potential change to the charging arrangements for legacy metering services. In line with feedback that costs to maintain legacy meters and associated services should be shared across all customers, we propose to seek the reclassification of legacy metering services as a SCS. We also propose to accelerate recovery of depreciation of legacy meters to achieve full cost recovery by 2030. More information is provided in Chapter 10.

Chapter 11: Alternative Control Services

ACS are typically user-specific or customer-requested services that are charged separately to the customer requesting or benefitting from the service (rather than costs being recovered from all customers through our network charges). These services are paid for by the person or entity receiving the service (i.e. user-pays).

The AER's *Final Framework and Approach* (F&A) for Ergon Energy Network for the 2025-30 regulatory control period classified public lighting (including security lighting), connection management services, enhanced connection services and ancillary services as ACS.[3]

Public lighting

The provision of public lighting is a critical service that plays an important role in enhancing safety and security in public areas. Due to the specific nature of public lighting and public lighting customers, we have had a stand-alone, discrete engagement process for public lighting. This engagement process has heavily influenced our proposed 2025-30 public lighting strategy.

As outlined in Chapter 11, our strategy is to continue the deployment of light emitting diode (LED) public lighting to achieve 100 per cent LEDs by 30 June 2030. This will result in energy savings for customers and support the transition to a net zero emissions future. As part of this strategy, we also propose to fund the upfront capital cost of the conversion of Rate 1 and Rate 2 assets to LED, extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights, and support a user-pays approach for smart control devices.

The proposed forecast revenue to be recovered from our public lighting tariffs in the 2025-30 regulatory control period is estimated to be $143 million compared to the total expected revenue of $141 million to be recovered from LED lights in the current 2020-25 regulatory control period. This modest step change aligns with Ergon Energy Network's investment in LED technology in both Rate 1 and Rate 2 assets. Ergon Energy Network does not propose any additional capex for conventional lights in the 2025-30 regulatory control period.

[3] AER, *Final Framework and Approach – Ergon and Energex 2025-30*, July 2023.

Other Alternative Control Services

Chapter 11 sets out our proposed approach to other ACS - ancillary services and security lighting.

Fee-based ancillary services include temporary disconnections and reconnections, supply abolishment, re-arrangement of connection assets, and meter tests. In addition to updating our forecast labour rates and overheads, we are proposing changes to service dimensions, such as travel time, time to complete a job and number of crew required. We are also proposing to rationalise our suite of services by discontinuing the service permutations which have had little to no uptake over the past three years and amalgamate services conducted on urban, short rural and long rural feeder types.

Quoted ancillary services include connection application management services, enhanced connection services and auxiliary public lighting services. Unlike in previous regulatory control periods, we are proposing to use labour rates specific to these quoted services for the 2025-30 regulatory control period to ensure we recover actual costs. We are also proposing to include a margin. This is in line with DNSPs in other jurisdictions, noting that it is intended to promote competitive neutrality.

Security lighting services generally involve installation, operation, maintenance and replacement of lighting equipment typically mounted to our distribution network poles and structures. As part of the F&A process, the AER agreed to our proposal to cease providing and installing security lights for new customers in the 2025-30 regulatory control period. Ergon Energy Network will continue to maintain and operate security lights for existing customers until they transition to alternative solutions.

Chapter 12: Other Regulatory Matters

Chapter 12 addresses a number of regulatory matters, including application of the AER's proposed approach to the classification of distribution services, incentive schemes and control mechanisms for ACS and SCS. This chapter also covers other regulatory requirements, including the requirement for a negotiating framework, jurisdictional schemes, nominated pass through events and contingent projects, and addresses our approach to confidentiality and assurance and certification requirements.

Attachments

Our Regulatory Proposal is complemented by supporting documentation, including a plain language overview and the Tariff Structure Statement. These documents are listed in each Chapter.

A snapshot of our Regulatory Proposal

Table 1: Standard control services

	2025-26	2026-27	2027-28	2028-29	2029-30
Forecast expenditures ($m, real $2024-25)					
Net capex	1,130.8	1,132.7	1,143.9	1,172.9	1,225.1
Opex (inc. debt raising costs)	470.8	473.6	476.4	477.9	480.4
Opening RAB ($m, nominal)	16,253.0	17,222.8	18,202.8	19,205.7	20,244.9
Revenue requirements ($m, real $2024-25)					
Annual revenue requirements (smoothed)	1,423.2	1,490.3	1,560.5	1,633.9	1,710.9
Weighted average cost of capital (WACC) (%)	6.04	6.09	6.16	6.27	6.38
X factor (%)	-4.71	-4.71	-4.71	-4.71	-4.71
Nominal increase in revenue (%)	7.64	7.64	7.64	7.64	7.64
Demand forecast 50 PoE (MW)	2,667	2,698	2,741	2,754	2,783
Customer numbers	806,760	813,557	820,224	826,549	832,754
Forecast energy consumption (GWh)	13,618	13,585	13,599	13,525	13,513

Table 2: Alternative control services

Matter	Position
Public lighting services	We are proposing to convert all existing conventional public lights to LED by 30 June 2030. We also propose to fund the upfront capital cost of the conversion of Rate 1 and Rate 2 assets to LED, extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights, and support a user-pays approach for smart control devices (to be offered to customers from 1 July 2026).
Other ACS	We are proposing to cease offering security lighting as a new installation from 1 July 2025. We will continue to maintain and operate legacy security lights. We are proposing changes to service dimensions for ancillary services. We are also proposing to rationalise our suite of services by discontinuing the permutations that have had little to no uptake over the past three years. We are proposing to use labour rates specific to quoted services to ensure the recovery of actual costs. We are also proposing to include a margin.

Table 3: Key positions

Matter	Position
Service classification	We broadly accept the AER's proposed service classification as set out in the Final F&A. We propose that legacy metering services should be reclassified as a SCS. We also propose to accelerate recovery of depreciation of legacy meters to achieve full cost recovery by 2030.
Control mechanisms	We accept the AER's control mechanism decision as set out in the Final F&A, namely: • revenue cap for SCS, and • price cap for ACS.
Incentive schemes	We accept the proposed application of the following incentive schemes as set out in the Final F&A: • Efficiency Benefit Sharing Scheme • Service Target Performance Incentive Scheme • Capital Expenditure Sharing Scheme • Demand Management Incentive Scheme, and • Demand Management Innovation Allowance Mechanism. However, we propose that the following incentive schemes should not apply in the 2025-30 regulatory control period: • Customer Service Incentive Scheme • Export Service Incentive Scheme, and • Service Target Performance Incentive Scheme (telephone answering measure)
Nominated pass through events	We nominate the following additional pass through events: • insurance cap event • insurer's credit risk event • terrorism event, and • natural disaster event.
Contingent projects	We have not proposed any contingent projects.
Tariffs	Our Tariff Structure Statement outlines our proposed tariff structures for the 2025-30 regulatory control period. We are proposing to: • strengthen the peak price signal • update time of use pricing windows • transition to two-way pricing • update controlled load tariffs, and • streamline existing tariffs.

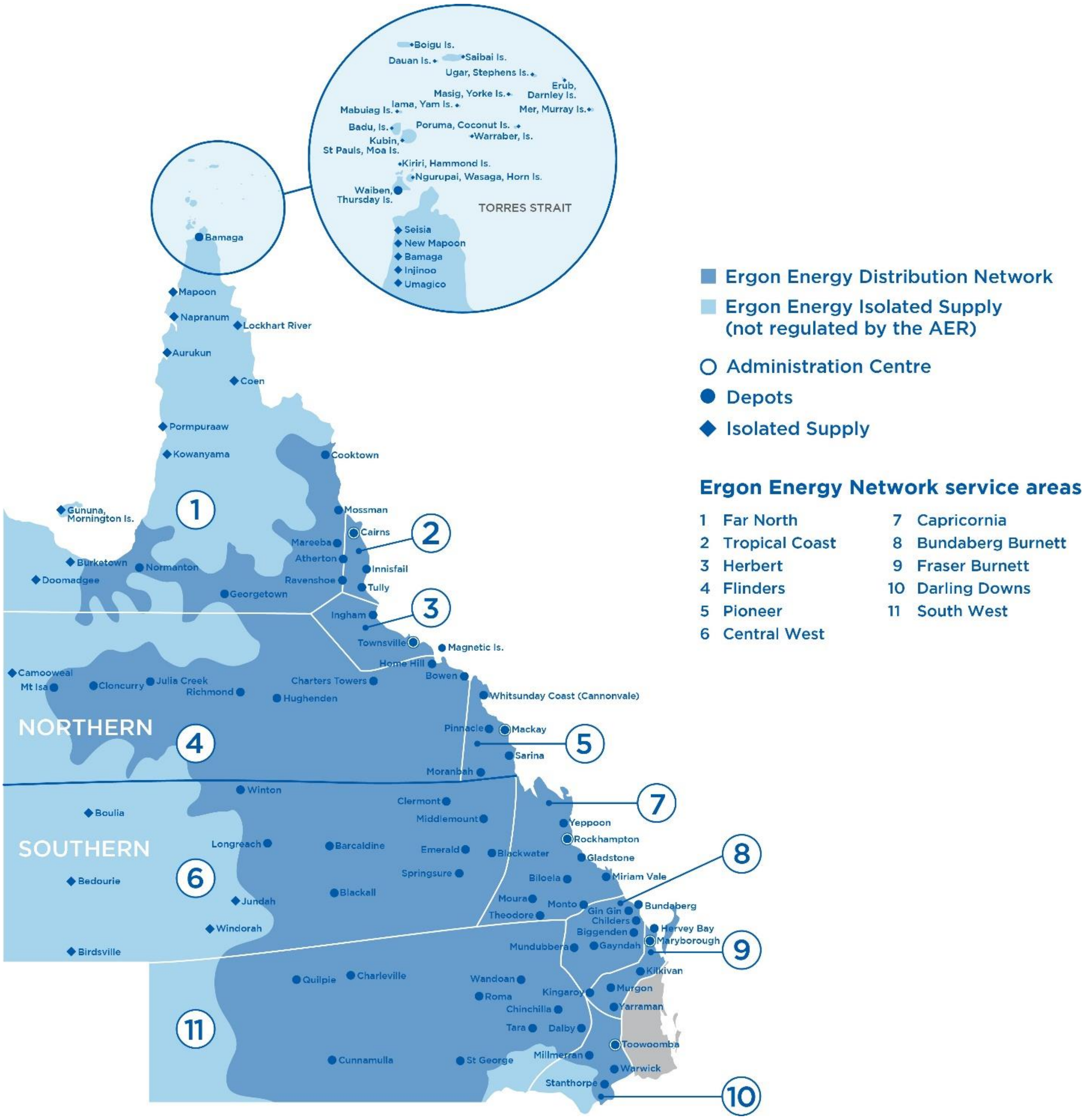
1.
Context for our Proposal

1.1 About Ergon Energy Network

Ergon Energy Network manages an electricity distribution network which supplies electricity to over 760,000 residential homes and commercial and industrial businesses across a growing population base of around 1.5 million people.

Taking supply from Queensland's transmission network service provider Powerlink, we provide electricity across a vast operating area of over one million square kilometres – around 97 per cent of the State of Queensland, with a maximum demand of around 2,600 MW and delivering around 13,800 gigawatt hours (GWh) per year. Figure 5 shows our distribution area.

Figure 5: Our service area



Our electricity network consists of 145,000 kilometres of overhead powerlines, 9,600 kilometres of underground power cables, one million power poles, 262 zone substations, 37 bulk supply substations and 98,000 distribution transformers. Based on line length, around 70 per cent of our electricity network runs through rural Queensland, typically with large distances between communities and one of the lowest population densities per network kilometre in the National Electricity Market (NEM). Ergon Energy Network has a proportionately high investment in sub-transmission assets, compared to the more urban networks, with voltage levels including 230 volt (V), 11 kilovolt (kV), 22kV, 33kV, 66kV and 132kV. It also has one of the largest Single Wire Earth Return networks in the world.

In addition, Ergon Energy Network owns and operates 33 isolated electricity networks that provide supply to around 7,000 homes and businesses in 34 remote communities in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, and Palm Island. Except for the supply network located in the Mount Isa-Cloncurry region,[4] these isolated networks are not subject to economic regulation by the AER and are not included in this Regulatory Proposal.

1.2 Energising regional Queensland communities

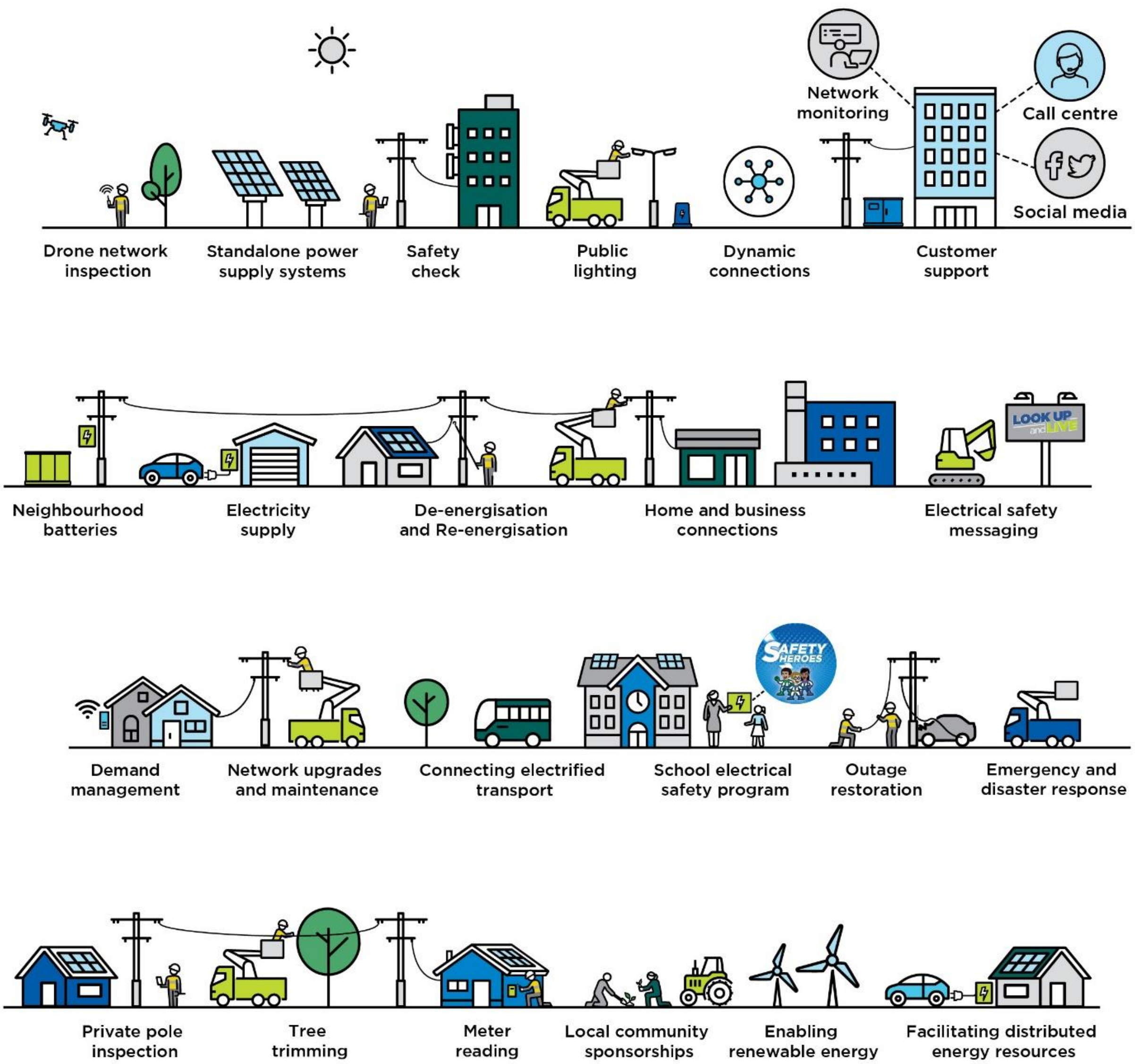
Ergon Energy Network services around 660,000 residential homes, 100,000 small to medium businesses and some of the State's largest commercial and industrial enterprises.

Our role as a distribution business is to provide a network of 'poles and wires' that deliver electricity to regional Queensland's homes and businesses. As illustrated in Figure 6, we provide a range of services, including:

- connecting customers to our network
- constructing the poles and wires used to transport energy across the distribution network
- monitoring and operating the network to ensure ongoing reliability of supply
- responding to power outages and fixing damage to the network, including after storms and natural disasters
- reading and testing basic accumulation meters, and
- building, operating and maintaining public lights.

[4] Section 10 of the *Electricity – National Scheme (Queensland) Act* 1997 provides that the AER is responsible for economic regulation of the Mount Isa-Cloncurry supply network.

Figure 6: Our services and activities



We recognise that the safe and cost-effective delivery of reliable electricity is essential to supporting our customers' lifestyles and the economic prosperity of the communities we serve and the State of Queensland as a whole.

Our employees also live and work across regional Queensland throughout Ergon Energy Network's distribution area, providing frontline services from 73 geographically dispersed service depots and offices. Our teams provide services to customers and respond to network faults and emergencies, as well as perform network maintenance and augmentation works across each area. As customers and community members, our employees appreciate the unique challenges faced by those living in the many and diverse local communities they serve.

Our customers and communities are at the centre of all that we do. Each area we service is unique, with different customer needs and preferences and different electricity supply challenges. Many of our regions are growing and the demand for power is increasing, particularly in the larger centres.

The way our network is managed and built is strongly driven by the expectations and needs of rural and regional residents, businesses, and communities. The vast size of Ergon Energy Network's distribution area and the geographically dispersed nature of the population means that our network needs to cover long distances and be sufficiently resilient to safely and reliably support our customers' domestic, commercial, and industrial needs and preferences now and into the future. How we invest in our network in regional Queensland is also influenced by a range of challenges, including:

- cost-of-living pressures
- increased uptake of DER, such as rooftop solar systems, batteries and electric vehicles, as well as large-scale renewable energy generation and storage
- strong economic growth and development throughout the region, principally in the tourism, renewable energy, agricultural and mining sectors, and
- increasingly harsh climate conditions and more intense and frequent natural disasters, including cyclones, flooding, and bushfires.

At the same time, we will be supporting the shift to renewable energies that will not only transform the State's energy system to deliver clean energy for householders and businesses but also contribute to accelerated growth in the economy and boost employment. Our role will be to ensure we have a well-integrated, smart, and resilient electricity system to deliver Queensland's clean energy targets and support employment, population, and economic growth.

Understanding the economic, social and environmental challenges of the region and the changes in our customers' preferences for how they interact with us and our network is critical to ensuring our investment plans will effectively manage and prepare our network for the demands of the future and deliver the best possible outcomes for our customers. In particular, we aim to address our customers' electricity affordability concerns by investing only what is necessary to meet the energy needs of regional Queensland, thereby minimising price increases.

To make sure we are meeting the unique and diverse needs of our communities and customers, we engage regularly with our customers and other stakeholders on their thoughts, needs, expectations and concerns. With our industry undergoing a period of rapid transformation, an open dialogue is critical for enabling diversity of thought, innovation and, ultimately, now more than ever, better, more sustainable, customer-focused solutions. Ergon Energy Network operates a coordinated, multi-channel community and customer engagement and performance measurement program. These conversations, and the focus they provide, are fundamental for creating real long-term value for our customers, our business, and regional Queensland.

1.3 What we have delivered for customers during 2020-25

During the current 2020-25 regulatory control period we have invested prudently and efficiently to build a strong foundation for the 2025-30 regulatory control period. This section provides an overview of how we have been delivering on the commitments we made to our customers and communities for 2020 and beyond and our financial and service performance to date.

1.3.1 Delivering on our customer commitments

Figure 7 details what we have delivered in the 2020-25 regulatory control period, against the key customer commitments that we made in our 2020-25 Regulatory Proposal.

Figure 7: Delivering on our customer commitments 2020-25

What we have delivered so far
Safety First

- As the network ages and the risk of equipment failure increases, a focus on maintaining safety outcomes for our people, customers and communities is paramount. Since 2020, we have invested in renewing and maintaining our poles, wires and other infrastructure to address asset safety risks and ensure we have the capability to respond to emergencies.
- Important investments in community safety have been made during this period, including education and awareness campaigns, such as the 'Next thing you touch', 'Take Care. Stay Line Aware.', 'Stay. Call. Wait.', 'Spot it. Report it.' and "Look Up and Live' campaigns. We have also undertaken targeted campaigns with industry stakeholders in response to an increase in building and construction, road transport and earthmoving related network safety incidents involving the public.
- We have engaged with landowners on the safety of privately-owned property poles and lines and the importance of maintaining powerline clearance. A trial inspection program has led to an advanced inspection method that proactively addresses the electrical safety and bushfire risks associated with unmaintained poles, complementing the responsibilities of the landowner to inspect and maintain any privately-owned poles and wires.
- To ensure safe clearances are maintained between our overhead powerlines and buildings or other structures, we have used aerial inspections to identify issues and engage proactively with landowners with structures under or too close to our lines. The issues identified are helping us to promote the importance of maintaining safe clearances from electricity infrastructure to councils and the construction industry.

What we have delivered so far

- Through our focus on continuous learning, critical controls around high-risk hazards and empowering our people with new digital capabilities, we have reduced the number of significant injuries in the workplace by around a third.

Affordable

- Over the past eight years (from 2016-2017 to 2023-24), distribution network charges for households have reduced by 5.54 per cent. However, the volatility in the wholesale market has offset much of those gains and impacted retail prices across the market.
- We are acutely aware of the cost-of-living pressures impacting our customers and have worked hard to ensure we have not spent any more than necessary to deliver our program of work. However, the economic landscape, characterised by higher than forecast inflation, increasing interest rates and disrupted global supply chains, has led to material cost increases for our business. This, along with our ongoing commitment to investing in the safety and reliability of our network, has contributed to us exceeding its AER forecasts for both opex and capex over the past three years.
- Changes implemented by Ergon Energy Network in 2020 represented a significant but transitionary step towards more efficient tariff structures and assignment arrangements for residential and small business customers. All customers within this group with capable meters are now assigned to network tariffs that reflect lower prices during most of the day and higher prices in the afternoon and evening (where triggers for network investment are strongest). Over a third of our customers are currently assigned to some form of cost-reflective network tariff structure.
- We are seeing more uptake of solar in our large business segments and growing interest across regional Queensland for commercial investment in large storage systems. Recognising these developments, we recently commenced the trial of a tariff for high voltage business customers which incorporated different rates and charges for usage at different times of the day as well as additional charges and rebates for exports to the grid.
- As part of our business-as-usual engagement, we have continued to seek feedback from our customers on the energy challenges they face and explore solutions to manage their consumption. For example, in collaboration with our sister company, Energex, our Network Pricing Working Group oversaw a trial of residential capacity tariffs to assess customers' understanding of and willingness to change their electricity consumption in response to capacity-based network tariffs.
- Throughout this period we have continued to work on strengthening our demand management capability to put downward pressure on our expenditure and limit the need for costly network investment. This includes expanding our PeakSmart air conditioning program, which now has over 12,500 customers enrolled across regional Queensland and our load control tariffs that provide a cheaper electricity rate for approximately 363,740 connected appliances.
- We have made our processes more efficient using digital innovation. For example, Robotic Process Automation across the timesheet entry process for our employees resulted in a reduction in hours of manual timesheet entries equivalent to around five full time employees. This time savings has allowed our Support Services Team to innovate in other areas and focus more on customers.
- Ergon Energy Network has remained conscious of the impact of the energy transformation on energy inclusion and, as such, we have been advocating for outcomes that deliver for our customers and ensure no one is left behind. This has included supporting the accelerated deployment of smart meters (which increase tariff choice for customers) across regional Queensland.

Secure

- Each day we build, operate and maintain the electricity distribution network in regional Queensland with a focus on providing a safe and reliable energy supply. Over the past three years, Ergon Energy Network has invested in the safety and performance of our network. Since commencement of the current period:
  - 830,000 assets have been inspected
  - 58,000 poles have been replaced or reinforced
  - 1,800 kilometres of conductor has been replaced

What we have delivered so far

- 51,000 customer service wires have been replaced or repaired
- 1.4 million spans of vegetation have been managed, and
- 10 substations have been refurbished, upgraded or rebuilt.

Importantly, this investment is beginning to show signs of decreasing the rate of asset failures. However, due to the age profile of the network in some areas of regional Queensland, this investment will need to remain escalated for some time to come.

- With an increase in our replacement program, we have focused on reducing expenditure elsewhere. For instance, we are delaying augmentation capex (augex) driven by population and capacity growth in some areas, with capacity increases proceeding in only the most critical areas of growth.
- Our readiness to respond to emergencies and major weather events has been a key priority. Ergon Energy Network's emergency response capability has been deployed on numerous occasions over the past three years due to major disruptive events, including severe storms, cyclones, bushfires, heatwaves and floods.
- Cyber security is an area of increasing focus and we continue to evolve our approach as a fundamental part of maintaining network and business security. ICT programs have been initiated to improve technology to deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment.
- While Ergon Energy Network's reliability performance for outage frequency continues to meet prescribed standards, our outage duration performance has been impacted by the need to undertake planned outages for our critical safety-driven program of works. Where we have failed to meet our commitments, we have provided a guaranteed service level payment to impacted customers.
- In response to the 2022-23 Queensland Household Energy Survey 73 per cent of participants agreed they were provided with a 'reliable energy supply', 61 per cent indicated they have a positive sense of security around their electricity supply, and 75 per cent consider the existing balance between cost and reliability is about right.

Sustainable

- We continue to transform our network into an intelligent grid so that our customers can leverage the many benefits of digital transformation, DER (like rooftop solar, battery storage and electric vehicles), and emerging technologies (such as the next generation of home and commercial energy management systems).
- Over the last three years we have seen a continuation of investment by customers in solar aimed at reducing energy bills. Other customers are investigating how to expand their solar investment, battery options or introduce an electric vehicle to their household or business.
- The continuing uptake of air conditioners, the installation of rooftop solar systems, and growing numbers of electric vehicles is changing the demand profile of the electricity distribution network. To manage the peaks and troughs that are arising on our network, we are continually evolving and growing our demand management program to respond to changes in customers' demand. We currently have a demand management portfolio of approximately 227MW in load and generation available to provide network support during system-wide and localised issues.
- We have introduced Queensland's first dynamic customer connections. This will enable us to dynamically operate the two-way power flows within the network's technical limits and allow more households and businesses to install rooftop solar, while ensuring the lowest cost, safe and reliable supply of electricity for all.
- We supported introduction of the emergency backstop mechanism to ensure we could maintain electricity system strength if too much solar was being fed into the grid. This tool enables large systems to be switched off in an energy emergency situation, as a last resort, for a short time at the direction of the Australian Energy Market Operator.
- Our SAPS solution is advancing to a pilot rollout following a trial of three network support SAPS in remote communities to improve power supply resilience. The lessons from these trials will support the development of regulations for these solutions and the installation of future SAPS.

What we have delivered so far

- Engagement with our customers and stakeholders on their needs and preferences has been an important part of our everyday business. Throughout the current period, Ergon Energy Network has continued to engage with customers, communities and other stakeholders through channels like the Queensland Household Energy Survey, Voice of the Customer program, Tariff Reform Working Group – Residential and Network Pricing Working Group, Customer and Community Council, and Talking Energy, as well as customer and stakeholder forums with industry-specific stakeholders. We have also been engaging on our investment plans for 2025 and beyond, working with a reference group, establishing two customer panels and undertaking other engagements to guide our planning for the new energy future.
- Strong demand for new network connections has driven significant customer-initiated project activity across our network. Since 2020-21 there has been a significant surge in residential subdivisions and increased numbers of new solar energy systems connecting to the network. In addition to high levels of new residential solar, the number of applications for connection of medium and large-scale renewable energy generating systems has also grown, with the connection of large projects with solar, wind and/or batteries. To date, we have completed connection applications for:
  - 27,500 residential customer connections and connection alterations
  - 6,400 small business connections and connection alterations
  - 1,800 large commercial and industrial business connections and connection alterations
  - 55,200 rooftop solar energy systems
  - 37 large renewable projects, with over 680,000 kVA of large-scale solar.
- Ergon Energy Network played a major role in supporting the Dulacca Wind Farm, one of the many major customer-initiated network connection projects that are transforming the State of Queensland. When fully operational, it will be the largest electrical connection to Queensland's distribution networks.
- Significant connection enquiries are being received around the electrification of transport, with alterations to airports, and mining and shipping ports all proposing carbon reducing projects that transfer energy to our electrical network. We are supporting government initiatives such as the Inland Rail project and major health infrastructure investments.

1.3.2 Our financial performance

We remain focused on our financial sustainability, acutely aware of our customers' cost-of-living pressures and the economic challenges associated with the energy transformation. This section discusses Ergon Energy Network's financial performance against the AER's forecasts for the current regulatory control period.

1.3.2.1 Operating expenditure

Table 4 details our actual opex performance against the AER's forecast (excluding debt raising costs) for the 2020-25 regulatory control period.

Table 4: Actual opex compared with AER forecast

	Current Period					
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**Total[1]**
AER opex forecast	463.4	456.8	451.0	444.8	438.7	**2,254.7**
Actual / estimated opex	450.8	441.2	483.3	490.2	484.0	**2,349.5**
Variance from forecast[2]	12.6	15.6	-32.3	-45.4	-45.3	**-94.8**

Notes:
1. Totals may not add due to rounding.
2. Positive value indicates we spent less than the forecast. Negative value indicates an overspend against forecast.

We are projecting to overspend the AER's opex forecast for the 2020-25 regulatory control period by $95 million in real 2024-25 terms. Over the 2020-25 period, the opex forecast was decreasing (in real terms), leading to an underspend in the first two years and a forecast overspend in the remaining three years.

The main drivers of our opex performance over the 2020-25 regulatory control period, and the above variances, include:

- reductions in planned maintenance activities at the beginning of the regulatory control period
- increasing vegetation management contract costs later in the period
- general market conditions and labour cost increases because of the Covid-19 pandemic, and
- growth in our capital program of work leading to increased labour and overhead costs.

1.3.2.2 Network capital expenditure

Table 5 details our actual network capex performance against the AER's forecast for the 2020-25 regulatory control period.

Table 5: Actual network capex compared with AER forecast

	Current Period					
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**Total[1]**
AER forecast	501.7	505.2	511.8	503.0	506.3	**2,527.9**
Actual / estimated network capex	747.5	823.8	909.0	877.7	897.8	**4,255.7**
Variance from forecast[2]	-245.9	-318.6	-397.2	-374.7	-391.5	**-1,727.8**

Notes:
1. Totals may not add due to rounding.
2. Positive value indicates we spent less than the forecast. Negative value indicates an overspend against forecast.

We are projecting to overspend the AER's network capex forecast for the current period by $1,728 million. The main drivers for our network capex performance over the 2020-25 regulatory control period are discussed below:

- **safety-related augex** – under Queensland's *Electrical Safety Act* 2002, Ergon Energy Network has an obligation to maintain minimum distances between our overhead conductors and the ground or adjacent structures. Early in this regulatory control period we decided to classify our clearance to structure and clearance to ground projects as augex rather than replacement expenditure (repex), since the primary driver for this work is not the age and condition of the assets, but rather that their height from the ground or other structure has changed over time. In our discussions on the ex post review and historical expenditure, we have separated clearance programs from our other augex programs to improve transparency and avoid confusion. We have identified a large number of clearance issues across our network and have worked with the Electrical Safety Office to prioritise our program of work across the 2020-25 and 2025-30 regulatory control periods. We are projecting expenditure of $200 million will be required to meet our obligations under the *Electrical Safety Act* in this regulatory control period

- **other augex** - excluding clearance projects, we are projecting to spend at the level of the AER's augex capital forecast for the current regulatory control period. Our average yearly spend across this period is approximately $40 million, which is an historically low level of expenditure. We have been able to maintain this level of expenditure through increasing the utilisation of our existing assets to meet growth in customer numbers and demand. However, we are forecasting a slight increase in the final years of the regulatory control period, primarily due to the completion of a project at Jubilee Pocket.
- **repex** - we are projecting to spend greater than the AER's repex forecast for the current regulatory control period by $1,274 million. The main drivers for our increased spend over the 2020-25 regulatory control period are:
  - the identification of a larger than expected number of defective poles requiring replacement due to a change to our pole serviceability calculation (as required by Queensland's Electrical Safety Code of Practice 2020 – Works) in response to an increasing number of in-service pole failures
  - a consequential increase in the need to replace transformers, cross-arms, overhead switches, and service cables associated with pole replacements, resulting in most of our distribution line asset categories being above the AER's forecast (although bundling of these works ensures our program is delivered efficiently and avoids the need to return to the same site to replace assets that fail subsequently), and
  - an increase in our reconductoring program to address the safety and reliability risks of an increase in unassisted conductor failure, in particular copper conductor.
- **connection capex (connex)** - we are projecting to spend greater than the AER's connex forecast for the current regulatory control period by $71 million. The main drivers for our increased spend are:
  - the unanticipated impact of Covid-19 on migration in regional Queensland and the associated increase in new connections, and
  - our 2020-25 investment proposals were completed on the back of a construction boom (prior to the Covid-19 pandemic) when a slowdown in construction was anticipated for the 2020-25 period. However, the construction sector proved to be more resilient than anticipated.

1.3.2.3 Non-network capital expenditure

We are projecting to spend greater than the AER's non-network capex forecast for the current regulatory control period by $282 million (refer to Table 6). The main drivers for our high non-network capex over the 2020-25 regulatory control period are:

- significant investment into non-network ICT systems, including replacing our Enterprise Resource Planning and Enterprise Asset Management systems and maturing our cyber security capabilities (more information is provided in section 5.3.2.2)
- the timing of investment in non-network property projects due to project phasing and contractor availability, and
- increased property, fleet and equipment costs due to general industry and market conditions, which has increased unit costs across projects and equipment.

In recognition of the amount of capex that we have invested in our non-network ICT systems above the AER forecast, we will exclude $121.3 million of ICT capex from our opening RAB forecast for the start of the 2025-30 regulatory control period. This amount was calculated as the difference between the AER's forecast and actual spend for the ex post period of 2018-19 to 2022-23. Excluding this capex from the RAB reduces our forecast revenues by $109 million over the next regulatory control period (accounting for the impact of incentive schemes).

Table 6: Actual non-network capex compared with AER forecast

	Current Period					
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**Total[1]**
AER forecast	103.1	101.2	91.7	77.5	84.1	**457.6**
Actual / estimated non-network capex	155.4	125.8	129.5	156.6	172.5	**739.9**
Variance from forecast[2]	-52.4	-24.6	-37.8	-79.1	-88.4	**-282.3**

Notes:
1. Totals may not add due to rounding.
2. Positive value indicates we spent less than the forecast. Negative value indicates an overspend against forecast.

1.3.3 Our service performance

To ensure our network remains safe and reliable, we continue to focus on delivering our major asset renewal program. These refurbishment and replacement works are essential to maintaining our current performance levels and ensuring we continue to provide a reliable and resilient network that meets the needs of our customers and regional communities.

We deliver our services to meet regulated target levels of electricity reliability (frequency of outages), responsiveness to restoration of power supply when outages occur (duration of outages), and customer call centre performance. The STPIS targets incentivise us to maintain or improve our service performance where customers are willing to pay. We either earn financial rewards or pay penalties based on our performance relative to average historical levels. The AER sets the STPIS targets based on our five-year historical performance, with the reward or penalty being applied annually as tariffs are established.

Table 7 shows our STPIS performance over the 2020-25 regulatory control period.

Table 7: Actual and forecast service performance (STPIS)

	Current Period				
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**
Unplanned SAIDI[1] (minutes)					
Urban	113.25	130.08	108.23	115.29	115.29
Short rural	265.85	305.16	283.48	280.66	280.66
Long rural	706.59	907.28	761.93	770.17	770.17
Unplanned SAIFI[2] (interruptions)					
Urban	1.11	1.24	1.15	1.19	1.19
Short rural	2.40	2.48	2.29	2.44	2.44
Long rural	4.55	4.83	4.39	4.68	4.68
Customer service (% answered in 30 seconds)					
Telephone answering	87.32	88.53	84.92	85.06	85.06

Notes:
1. SAIDI = System Average Interruption Duration Index.
2. SAIFI = System Average Interruption Frequency Index.

1.4 Our operating environment

Ergon Energy Network is operating in a time of change and uncertainty. The energy transition to more renewables is driving once-in-a-generation change that requires a whole-of-system transformation.

The growth in electric vehicles, battery energy storage systems, solar systems and smart metering is changing the way we live. At the same time, Queensland has experienced unprecedented challenges associated with the global Covid-19 pandemic and is now facing rising cost-of-living pressures. This means we need to be prudent, and only invest what is necessary.

However, Ergon Energy Network does not want to be in a position in the future where we place the burden to pay on the next generation of customers because we have not acted today. We also need to consider the impact of the energy transition on energy inclusion, and advocate for outcomes that deliver for all our customers and communities.

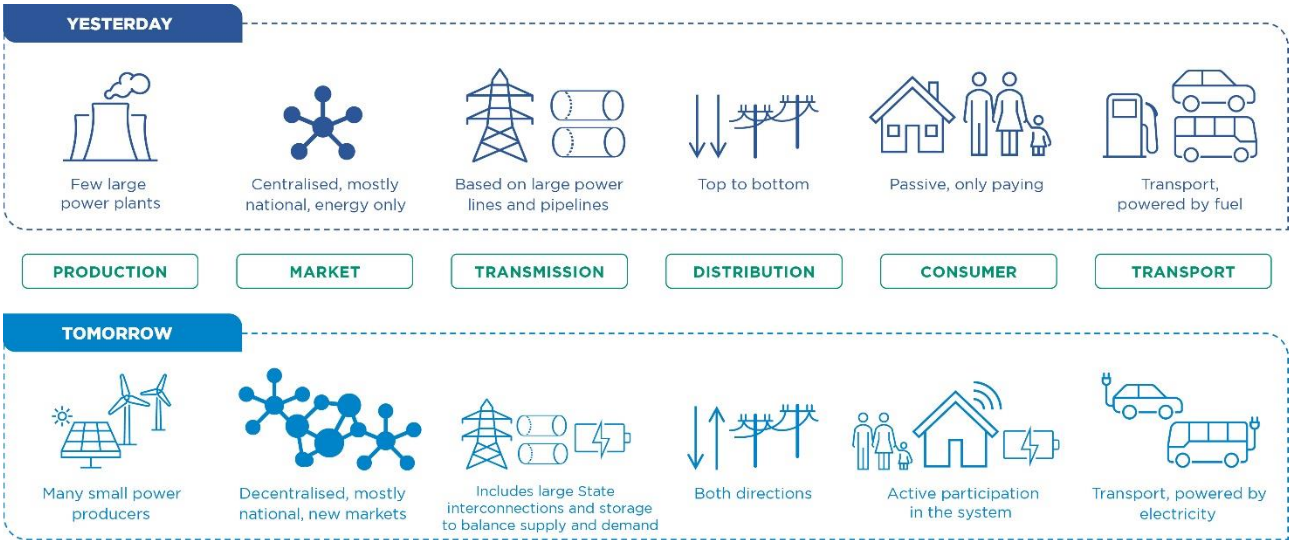
1.4.1 The energy transformation

With a changing environment and continuing increases in the cost-of-living, providing the electricity infrastructure to support our energy future has never been more important than now.

As illustrated in Figure 8, supplying energy to a home or business involves several different functions. Traditionally, the energy supply chain has involved generating energy (typically from gas or coal), transmitting the energy using poles and wires over long distances from power stations to where residential and business customers are and distributing the energy over smaller poles and wires.

With increased customer uptake of renewables and other technologies, people are rapidly changing both how they use and what they expect of the electricity network. This requires a rethink about the best way to plan for the future.

Figure 8: The energy transformation



1.4.1.1 The shift to a clean energy future

The Queensland Government's *Queensland Energy and Jobs Plan* outlines how the shift to renewable energies will be implemented in Queensland and commits to a 70 per cent renewable energy target by 2032, 80 per cent by 2035 and net zero emissions by 2050. While Ergon Energy Network will not have any investment projects directly related to the plan, our distribution network will support the shift to a clean, low carbon energy future by enabling the connection of more DER and the electrification of transport, consistent with government and customer environmental objectives.

1.4.1.2 Electrification of everything

'Electrification of everything' is a critical component in the strategy to reach net zero emissions, with electricity generated from renewable sources set to become the primary source of energy in Australia. Solar panels, battery energy storage systems, electric vehicles, home management systems and other devices will increasingly empower our customers to generate, store and manage their own electricity. The network can also benefit from the flexibility of these loads to flatten the peaks and troughs in network demand and defer network augmentation. As we continue to support the electrification of everything by enabling customers to install these technologies, the reliability, safety and security of our electricity will become even more important.

1.4.1.3 The new role of Distribution System Operator

Ergon Energy Network will continue to expand the coordination of energy use and supply to customers by dynamically operating two-way power flows in the distribution network within technical limits and optimising available DER, including electric vehicles and community batteries. This will enable our customers to leverage the many benefits of digital transformation and DER to manage their energy usage and costs, while also allowing us to leverage emerging technologies to manage our network assets more efficiently. The *Queensland Energy and Jobs Plan* sets out plans to define the roles and responsibilities of Queensland's Distribution System Operator in advance of the appointment of Energy Queensland (our parent company) as the Distribution System Operator in Queensland to better coordinate energy use and supply to customers.[5]

1.4.1.4 Growth in the uptake of DER

The volume of DER, like solar systems, battery storage and electric vehicles, connecting to our network is expected to grow over the next five to ten years. We are committed to supporting continued customer uptake of these technologies and their effective integration into the system, while continuing to maintain the reliability of our network. For example, with the potential for up to 118,000 additional electric vehicles to be on the roads in regional Queensland by 2030, the connection of charging facilities for electric vehicles is an important consideration for the 2025-30 regulatory control period.

1.4.1.5 Challenges of minimum demand

The rapid growth of solar generation from house rooftops and solar farms during daylight hours is resulting in the need to manage the rising challenge of minimum demand on the network. Minimum demand can best be described as the lowest energy demand across an electricity network at a point in time. This can cause issues around local power quality that can be harmful to customer

[5] Queensland Government, *Queensland Energy and Jobs Plan,* September 2022, p. 37.

appliances as well as the network. At the system level, it can impact power system security, threatening its ability to withstand major events unless carefully managed. Our network will need to continue to deploy solutions that help to 'soak-up' the generation from solar and put it to good use for customers.

1.4.1.6 Energy storage

Energy storage will be important in providing a balance between supply and demand by enabling load shifting (i.e. customers storing their excess power generation to use in peak periods and reduce their costs) to avoid network constraints. With an expected decline in battery costs over time, the installation of varying sized batteries in Queensland homes and businesses will likely increase. Customers will be able to use the stored energy and avoid paying higher prices for network supply during peak periods or can consider exporting the stored energy to the grid during a peak period. Electric vehicles also present a future opportunity for mobile storage, with vehicle-to-grid charging having the potential to balance loads.

1.4.1.7 Security of critical infrastructure

Security of critical infrastructure is an area of increasing focus for all utility providers given the growing threat to essential services and businesses. As a responsible entity for a critical infrastructure asset, we are bound by the *Security of Critical Infrastructure Act* 2018 which requires us to proactively manage risks to ensure the security of our infrastructure, both physical and cyber. As the energy transformation continues to evolve with more interconnection and digitalisation, it requires even greater effort to manage risk. We are continuously updating our approach to an increasingly complex physical and cyber security environment.

1.4.1.8 Stand-alone power systems

Providing electricity via traditional poles and wires to customers at the fringe of the national grid or in remote or hard to access locations is increasingly more inefficient and costly. With the rapid advancement in technology and the decrease in the cost of off-grid supply technologies, it is important for Ergon Energy Network to consider alternative supply options, such as SAPS, to drive improved customer outcomes from both a cost and reliability perspective.

1.4.2 Climate change and the environment

Regional Queensland experiences challenging climate and environmental conditions in which to operate an electricity distribution network, including:

- high rainfall areas with rapid vegetation growth
- high exposure to cyclones in the coastal northern and far north regions
- severe storm and lightning activity, bushfires, flooding, and storm surges
- salt spray in coastal areas, and
- periods of sustained high temperatures and high humidity.

Environmental factors can have a significant impact on the life of our assets and create safety and reliability problems for the network. They are also a key driver for maintenance and asset replacement expenditures.

The changing climate and increasing frequency of major disruptive weather events and the resilience of our network remains front of mind, as do customer expectations for quick restoration of supply following these events.

1.4.3 Economic factors

The energy transformation is expected to drive investment into the Queensland economy, creating new jobs and industries such as renewable hydrogen. With Queensland's economy and population expected to grow in coming years, Ergon Energy Network will need to provide the infrastructure to support more connections and increased demand. At the same time, cost-of-living pressures are likely to remain a key concern for our customers and communities.

1.4.3.1 Queensland's growing economy

The Queensland Government's 2023-24 State Budget projects that the Queensland economy will grow by around 2.75 to 3 per cent annually from 2023-24 onwards and that there will be continued low levels of unemployment. Queensland's population is also expected to grow during the 2025-30 regulatory control period. The expected strong economic and population growth in regional Queensland will drive new home and business connections to the network and require a reliable, sustainable supply of electricity in addition to current demand.

1.4.3.2 Increases in the cost-of-living

Elevated inflation and cost pressures on consumers remain high and are unlikely to ease significantly in the short-term. Rising interest rates, which not only affect household budgets directly but also indirectly through increased consumer pricing (due to higher business interest rates), are placing further pressure on customers. Interest in ways to reduce or change consumption to lower electricity bills is increasing among our customer base and is an important consideration in our Regulatory Proposal.

1.4.3.3 Labour and skills shortages and supply chain issues

With the State's economy and population set to climb, the availability of skilled technical and trade resources and materials and equipment is essential to ensuring that Ergon Energy Network has the capability to build the infrastructure needed to cope with increasing supply demands and resource the electricity network of the future. However, we are operating in an environment in which recruiting appropriately skilled staff and procuring materials and equipment to build and maintain our network is challenging, particularly when global supply chains are still recovering post Covid-19 and have been further disrupted by the war in Ukraine.

1.4.4 Ongoing regulatory change

Our industry operates with oversight from several regulators, including the AER, the Queensland Competition Authority, and the Queensland Government's Department of Energy and Climate and Electrical Safety Office. With the energy transition gathering pace, our regulatory environment continues to evolve. Further changes to the rules that govern the operation of the NEM will have an impact on how we operate and manage our distribution network now and into the future.

2.
Customer and Stakeholder Engagement

Key messages:

- Engaging with and listening to our customers is a fundamental component of our business-as-usual activities and has been integral to the development of this Regulatory Proposal.
- Our Regulatory Proposal has been informed by a comprehensive engagement program, using a variety of engagement channels and techniques, and is an outcome of the valuable insights and preferences provided by our customers and stakeholders.
- Customers and stakeholders have shared their views on a range of themes, including the energy challenges they and their communities face, as well as on targeted issues on which we sought specific feedback.
- Overall, customers have told us that they value the services we provide and how we go about keeping the lights on. However, they have also told us that affordability of electricity is their primary concern, both from a cost-of-living and cost-of-business perspective.
- In response to customer feedback, we have sought to strike the right balance between investing in the network to provide clean, reliable and smart electricity and efficiently delivering electricity services in the most affordable way.

2.1 Overview

Engagement with our customers and stakeholders has always been a fundamental aspect of our daily operations at Ergon Energy Network. We built upon this foundation in establishing our Customer and Stakeholder Engagement Strategy (Attachment 2.01) and Customer and Stakeholder Engagement Plan (Attachment 2.02) through proactive engagement and co-design with customers, our Customer and Community Council, and various other stakeholders representing a cross-section of customer cohorts. We committed to working in collaboration with our customers and stakeholders to shape and deliver a Regulatory Proposal that not only reflects the outcomes of our engagement process but also has the endorsement of regional Queensland customers and communities. This chapter discusses how we have actively involved our customers and stakeholders in this journey, integrating their valuable insights and preferences into the development of this Regulatory Proposal.

Our customers are at the heart of everything we do at Ergon Energy Network. We are dedicated to enhancing the service experience today, while evolving to meet future needs. We take pride in our role in keeping the lights on across regional Queensland, especially during a period of significant transformation in the energy industry. The regulatory reset has been a crucial opportunity for us to strengthen our business-as-usual engagement activities, enabling us to delve deeper into understanding and responding to what truly matters to our customers and stakeholders. During this process we established our Voice of the Customer Panel, with a focus on forging partnerships to ensure that our engagement directly contributes to delivering clean, reliable and smart electricity services in the most affordable way, and ultimately a positive outcome for our customers.

2.2 Engagement context

In developing our Regulatory Proposal engagement program we first set out to understand the AER's *Better Resets Handbook: Towards Consumer-Centric Network Proposals* (December 2012), also known as 'the *Better Resets Handbook'*, which seeks to encourage networks to better engage and have consumer preferences drive the development of their Regulatory Proposals.

The *Better Resets Handbook* identified three key themes for engagement, including 'Nature of Engagement', 'Breadth and Depth', and 'Clearly Evidenced Impact', which is depicted in Figure 9.

Figure 9: Engagement Strategy Building Blocks

Engagement Strategy Building Blocks		
Nature of Engagement	**Breadth of Engagement**	**Clearly Evidenced Impact**
Sincerity of engagement	Accessible, clear and transparent engagement	Regulatory Proposal linked to consumer preferences
Consumers as partners	Consultation on desired outcomes and then inputs	Independent consumer support for the Regulatory Proposal
Equipping consumers	Multiple channels of engagement	
Accountability	Consumers' influence on the Regulatory Proposal	

Nature of Engagement is concerned with sincerely partnering with consumers and equipping them to effectively engage in the development of their Regulatory Proposals. The intent is to treat the consumer as a partner, to understand and reflect their preferences within the Regulatory Proposal, produce the proposal by focusing on the outcomes sought and, upon regulator approval, embed the change for implementation within the agreed timeframe.

Breadth and Depth relates to the scope of engagement with consumers and the level of detail at which network businesses engage on the issues identified from the consumer's perspective. The intent is that Ergon Energy Network transparently sets out its Customer and Stakeholder Engagement Plan, based upon the long-term outcomes for consumers, embracing multiple channels of engagement and, where possible, using the International Association of Public Participation (IAP2) Spectrum of Public Participation as already adopted by Ergon Energy Network.

Clearly Evidenced Impact means the issues addressed and the outcomes pursued represent the consumer's own preferences as captured through structured engagement sessions, and where the consumer's voice is obtained through independent facilitation especially where they are vulnerable. The intent is to safeguard the consumer's interests and understand the sentiment free of undue influence by Ergon Energy Network.

We have adopted the AER's engagement themes and building blocks into our own Customer and Stakeholder Engagement Framework. Our approach is not only aligned with these principles but is also deeply embedded in every aspect of our engagement activities. For a detailed account of how our engagement program has delivered on the AER's expectations, please refer to our

Engagement Summary Report (Attachment 2.03). This document provides comprehensive insights into our journey of elevating engagement to a core business priority, ensuring that our Regulatory Proposal is both reflective of and responsive to the needs and preferences of our customers and stakeholders.

2.3 Customer and stakeholder engagement focus

Building on our business-as-usual engagements, we have undertaken a comprehensive engagement program, based on best practice principles for customer and stakeholder engagement - the foundation and framework for the way we do business. We have aligned our engagement program with the AER's expectation for customer-driven priorities to produce this Regulatory Proposal. With a strong focus on affordability, we are keeping downward pressure on our network prices, simplifying our network tariffs, and providing clean, reliable and smart electricity services that not only keep the lights on, but meet the long-term interests of all regional Queenslanders.

Our aim has been to engage with and listen to the voice of our diverse customers and transform our distribution network to deliver affordable, sustainable energy services and solutions to over 760,000 residential homes and commercial and industrial businesses, across a growing population base of around 1.5 million people. In the ever-shifting energy landscape, where the cost-of-living is a significant concern for many Queenslanders, we have made affordability one of the key foundations of our decision-making.

We recognise that the safe and cost-effective delivery of reliable electricity is essential to supporting our customers' lifestyles and the economic prosperity of the rural and regional communities we serve and the State of Queensland as a whole.

Our customers and communities told us they have high expectations of Ergon Energy Network. They want us to give them a chance to talk about their energy challenges, understand how they affect us all, and work together to find sustainable, cost-effective solutions for the future. They want to be partners in this process, and we have been committed to a partnership approach.

We recognise the critical role our customers and stakeholders have at each stage in the engagement process. Throughout this regulatory control period, we have fostered collaboration with our customers, their representatives, and our wider stakeholders, directly engaging with them on a range of topics that are important to them, like addressing affordability and value, providing a well-integrated, smart, and resilient electricity network to facilitate the energy transition, and enhancing customer service.

Input from customers and stakeholders spans a wide range of engagement activities that have taken place since 2020, throughout the 2020-25 regulatory control period. It has been invaluable in shaping not only our current business decisions and planning but also our future strategies for the period from 2025 to 2030.

2.4 Engagement approach

Ahead of the 2025-30 regulatory control period, our commitment to crafting a consumer-centric Regulatory Proposal has had unwavering support from the Energy Queensland and Ergon Energy Network Boards and Executive Leadership Team.

In alignment with this commitment and recognising the substantial transformation underway in the energy sector, with a particular emphasis on the regulatory landscape, the Energy Queensland Board and Executive appointed an Executive General Manager Regulation to spearhead effective reforms that meet our customers' demands and facilitate Ergon Energy Network's role in the energy transformation. Responsibility for the Regulatory Proposal engagement program sits with both the Executive General Manager Regulation and the Chief Customer Officer, who leads our customer and community engagement portfolios.

Building on our longstanding commitment to sincere and genuine engagement, our goal has been to introduce a fresh perspective to regulatory engagement, working in partnership with, and placing the customer at the centre. We wanted to understand the broader community context and how energy forms a part of regional Queenslanders' thinking about their future challenges. Within that context we set a range of engagement and consultation activities, principles, and methods to inform and engage customers and other key stakeholders in the development of our Regulatory Proposal.

With this in mind, we set out to reconfirm our engagement principles, as depicted in Figure 10, which have formed the foundation for our business-as-usual engagements with customers and stakeholders. These principles, previously outworked with our customer advocates, have guided our approach throughout the regulatory determination process.

Figure 10: Principles of engagement

Our principles of engagement have not only been integral to our Regulatory Proposal engagement approach, but have also evolved in the context of aligning them with the AER's principles in the *Better Resets Handbook* while mapping our approach.

See our Engagement Summary Report for further detail on the commitments made in our Customer and Stakeholder Engagement Plan, to deliver against the *Better Resets Handbook* principles and engagement expectations, and our progress against those commitments throughout our engagement to date.

2.5 Engagement program and outreach

Building on our business-as-usual customer and stakeholder engagements, discussions with Ergon Energy Network stakeholders in July 2022 confirmed our intention to ensure proactive consultation and co-design of our engagement strategy and associated engagement plan to ensure they both supported and met our customers' needs and expectations.

We established the co-design engagement methodology in 2022 to enable customers and stakeholders to have their say and contribute to developing our Customer and Stakeholder Engagement Strategy. It was carefully shaped with input from a diverse range of Ergon Energy Network customers, our Customer and Community Council, and various stakeholders representing a cross-section of customer cohorts.

Following development of this strategy, in March 2023, we published our Customer and Stakeholder Engagement Plan, which was developed in further collaboration with our Customer and Community Council and RRG to bring the strategy to life.

Both the strategy and plan were designed mindful of best practice customer and community engagement described by both in the *Better Resets Handbook* and the IAP2.

2.6 Reset Reference Group

We established a RRG to facilitate customer and community participation in the 2025-30 Regulatory Proposal process. The RRG's primary purpose has been to engage in constructive collaboration with Ergon Energy Network to develop and execute our Customer and Stakeholder Engagement Plan, as well as to challenge us on our approach to our investment and revenue recovery matters related to our Regulatory Proposal in the interests of ensuring positive outcomes for customers.

Officially established in October 2022, the RRG has had direct input to and overseen our engagement and collaboration with customers, customer representatives and other stakeholders, as we have sought to ensure that our Regulatory Proposal reflects the long-term interests of customers, both residential and business, and our wider communities, against efficiency and affordability performance indicators.

The RRG has helped shape the design of and overseen many of the engagements outlined in this Regulatory Proposal and provided expert guidance to Ergon Energy Network on numerous topics, including network tariff challenges, tariff structure design, the Connection Policy 2025-30, Network Capital Governance Framework, cyber security and non-network ICT investments, and smart meter data purchase options.

Ergon Energy Network's commitment to the success of the RRG has been underpinned by four key actions:

- our Energy Queensland and Ergon Energy Network Boards and Executive Leadership Team have provided their strong support for the RRG as an independent body
- the RRG has been empowered to evaluate our Regulatory Proposal with rigor. This includes reflective analysis and feedback in relation to issues as we progressed the development of our Regulatory Proposal
- the RRG has provided an independent feedback loop across all engagement activities, enabling us to consider process improvements and enhance opportunities for further dialogue throughout the engagement process, and
- the RRG has provided an independent report on our Draft Plan that reflected its assessment of the engagement undertaken to that point in time and how they believe that engagement has shaped our investment and revenue recovery plans, with a further report to be provided post submission of this Regulatory Proposal.

2.7 Engagement roadmap

In August 2022 we held a customer and stakeholder co-design five-day online 'Recollective' workshop process to inform our engagement strategy for our Regulatory Proposal. We were keenly interested in the views of a representative range of customer and stakeholder participants. Ergon Energy Network Directors, Executives and project staff, as well as AER and key Queensland government representatives also participated as observers. The outcomes of the 'Recollective' workshop process guided the development of our Customer and Stakeholder Engagement Strategy and subsequent Customer and Stakeholder Engagement Plan.

Through the 'Recollective' workshop process several specific customer cohort 'target audiences' were identified as priorities for our engagement on the Regulatory Proposal. We also identified the different topics and issues that these target audiences may be interested in and the different communication and engagement needs they may have to enable active participation. In addition to identifying target audiences to engage, customers and stakeholders who participated also told us of the energy challenges they face, which provided us with early insights into some of the key issues to be considered as part of our Regulatory Proposal development. Our Engagement Summary Report provides a comprehensive summary of the engagement activities undertaken, customer and stakeholder insights and recommendations, and how we have responded.

These early insights helped us to develop some overarching key themes and topics to frame and guide our engagement conversations with customers as outlined in Figure 11. As part of our engagement planning, we also developed an engagement roadmap that outlines several distinct phases of engagement over our Regulatory Proposal development, as depicted in Table 8. Importantly, the overarching themes and topics and the phases of engagement approach were endorsed by our Customer and Community Council and the RRG - an important part of the co-design process.

Figure 11: Engagement Themes

Four phases of customer and stakeholder engagement have occurred to date in the development of this Regulatory Proposal.

Table 8: Phases of engagement

PHASE	PURPOSE AND OBJECTIVE	TIMEFRAME	PURPOSE/OBJECTIVE
PHASE 1	GATHER & PLAN	By end-2022	• Gather insights from our business-as-usual engagement activities and other interactions with customers and stakeholders. • Gather insights from our existing customer research and insights program of activity and research conducted to date. • Gain a further understanding of our customer and stakeholder energy needs and engagement preferences to inform our engagement planning through a customer and stakeholder workshop/online forum. • Incorporate all insights and understanding into an engagement strategy and engagement plan outlining our approach and proposed activities to engage with our customers and stakeholders throughout the regulatory proposal process.
PHASE 2	LISTEN	Feb – Jun 2023	• Establish our key engagement structures as part of the engagement approach and plan. • Engage directly with customers and stakeholders across regional Queensland to confirm insights and understandings from Phase 1 ‘Gather & Plan’. • Catalogue what customers told us in our engagement conversations about their energy needs now and into the future and identify any gaps and new issues/insights provided. • Review conversations undertaken to determine key customer and stakeholder issues to inform in-depth future conversations.
PHASE 3	SHARE & EXPLORE	Jun – Aug 2023	• Explore key issues with our customers and stakeholders in-depth and analyse options, including trade-offs that may be required. • Gather insights from our in-depth customer and stakeholder conversations and evaluate how these insights and their preferences can influence the Regulatory Proposal. • Develop specific options based on customer and stakeholder preferences to be incorporated into our Draft Plan.
PHASE 4	TEST & REVISE	Sep 2023 – Jan 2024	• Engage with customers and stakeholders on our Draft Plan and test options outlined. • Explore any additional ‘trade-offs’ that may be required around preferences and seek common agreement where possible. • Incorporate feedback to Draft Plan and additional insights and preferences provided into Regulatory Proposal. • Submit Regulatory Proposal to the AER.
PHASE 5	FINALISE	Apr - Sep 2024	• Evaluate AER Issues Paper on our Regulatory Proposal. • Engage with customers and stakeholders to provide information required in informing their response and submissions to the AER Issues Paper consultation. • Evaluate customer and stakeholder feedback to the AER Issues Paper and further engage with customers and stakeholders to clarify the insights and feedback they provide through the AER Issues Paper consultation. • Consider all insights and feedback received to finalise our Revised Regulatory Proposal. • Submit Revised Regulatory Proposal to the AER.
PHASE 6	FUTURE	Apr 2025	• Conduct lessons learned exercise with our customers and stakeholders to inform our engagement activities going forward. • Implement 2025-2030 Regulatory Proposal plans. • Monitor and evaluate delivery effectiveness, including reporting on progress against meeting our customer and stakeholder expectations and continually engage with them as part of business-as-usual engagement practices.

Note. As per our Customer and Stakeholder Engagement Plan, Phases five and six will occur throughout 2024-25.

2.8 Engagement channels and techniques

To ensure we are meeting the unique and diverse needs of our customers and communities we regularly engage with our customers and other stakeholders on their thoughts, needs, expectations and concerns. Below is a high-level overview of our business-as-usual and bespoke engagement activities undertaken to date, by customer and stakeholder segment, that have informed thedevelopment of our Regulatory Proposal.

We have utilised a wide variety of engagement methods and channels to ensure the overall regulatory engagement program achieves both deep and broad engagement with a diverse cross-section of customers and stakeholders. This is depicted in Table 9, noting engagements for Phase 5: Finalise, and Phase 6: Future, have not been included as they are yet to occur.

Table 9: Overview of Customer and Stakeholder activity

	Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023
CUSTOMER ADVOCATES	**Residential and Business Advocates**	Customer & Community Council	✓	✓	✓	✓
		Reset Reference Group	✓	✓	✓	✓
		Network Pricing Working Group	-	-	✓	✓
	Agriculture Sector	Agriculture Forum	✓	✓	✓	✓
	Developer Representatives	Urban Development Institute of Australia (UDIA) – Regional Committee	✓	✓	✓	✓
	Representatives from Local Government and Department of Main Roads and Transport	Public Lighting Forum	✓	✓	✓	✓
COMMUNITY STAKEHOLDERS	**Community Stakeholders**	Queensland Energy and Jobs Plan Roadshows *(Note: Ergon Energy Network speaker at roadshows)*	-	✓	-	-
		Energy Queensland Board Stakeholder Events	✓	✓	✓	✓
	Local Councils	Area Manager meetings with local council representatives	✓	✓	-	-
	Local Councils/Community	Disaster Planning Work Groups – Distributed and Local Groups	✓	✓	✓	✓
	Edge of Grid Community	Microgrid Feasibility Engagement	-	✓	-	-
	Battery Neighbours	Local Network Battery Plan Engagement	-	✓	-	-

Stakeholder		How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023
RESIDENTIAL CUSTOMERS	**Residential Customers - reliable representation of customer base (*Note: included many customer cohorts listed below*)**	Voice of the Customer Panels	-	✓	✓	✓
		Queensland Household Energy Survey 2023 *(Note: 1,816 Ergon Energy Network customers responded)*	-	✓	-	-
	Residential Customers	Customer Focus Group Workshops x 2 (focus on capex incl. fleet, property, ICT and DER-related investments; opex; and Draft Plans)	-	-	✓	✓
		Residential Customer Tariff Interviews	✓	-	-	-
		Residential Network Capacity Tariff Trial *(Partner: Ergon Energy Retail)*	✓	✓	✓	✓
	Residential Customers who have had a recent interaction with Ergon Energy Network	Customer Experience Measurement Survey *(Note: Customer Satisfaction based surveys sent to customers post interaction)*	✓	✓	✓	✓
	Community Members	Customer Satisfaction and Net Trust Score Survey	✓	✓	✓	✓
	Future Voices – Energy Innovators	Solar, battery and EV owners – Perspective Gathering Workshop	-		-	-
	Future Voices – Youth	Young people - Perspective Gathering Workshop	-	✓	-	-
	Future Voices – Community Campaign	Online campaign – Talking Energy	✓	✓	✓	✓
	Quiet Voices – Renters	Renters (tenants) - Perspective Gathering Workshop	-	✓	-	-
	Quiet Voices – Seniors (definition: self-funded retirees and pensioners)	Seniors - Perspective Gathering Workshop	-	✓	-	-
	Quiet Voices – People living with a disability	People living with a disability - Perspective Gathering Workshop	-	✓	-	-
	Quiet Voices – Life Support Customers	Life Support Customer - Perspective Gathering Workshop	-	✓	-	-
	Quiet Voices – Culturally and linguistically diverse	Culturally and linguistically diverse - Perspective Gathering Workshop	-	✓	-	-
	Quiet Voices – Indigenous	Indigenous - Perspective Gathering Workshop	-	✓	-	-

	Stakeholder	How – Engagement Activity	Phase 1 Gather & Plan 2022	Phase 2 Listen Feb-May 2023	Phase 3 Share & Explore Jun-Jul 2023	Phase 4 Test & Revise Oct-Nov 2023
BUSINESS CUSTOMERS	**Small to Medium Enterprises (SMEs)**	Small Business – Perspectives Gathering Workshop	-	✓	-	-
		Individual customer interviews – network tariffs	-	-	✓	-
		This customer cohort also represented in Customer and Community Council/Network Pricing Working Group/Agriculture Forum engagements (see above)	✓	✓	✓	✓
	Developers	Customer experience journey mapping – developers' connection process	✓	-	-	-
	Large customers, commercial and industrial	Large Customer Forum x 2	-	-	✓	✓
		Large customer individual meetings – network tariff impacts	-	-	-	✓
	Agriculture	Solar Soak Tariff Desktop Analysis *(Trial Partner: Bundaberg Regional Irrigators Group)*	✓	-	-	-
		This customer cohort also represented in Customer and Community Council/Network Pricing Working Group/Agriculture Forum engagements (see above)	✓	✓	✓	✓
	Sugar Industry	Sugar Mill Forum x 2	-	✓	✓	✓
ENERGY PARTNERS	**Energy Retailers**	Energy Retailer Meetings *(Note: main 6 retailers in Queensland bi-monthly)*	✓	✓	✓	✓
		Energy Retailer Forum *(Note: all energy retailers)*	-	-	✓	✓
		Annual Energy Retailer Satisfaction Survey	-	✓	-	-
	Electrical Contractors	Electrical Contractor Peak Body Meetings *(Note: meetings individually with Master Electricians Australia and National Electrical and Communications Association)*	✓	✓	✓	✓
		Energy Academy Forum *(Note: Electrical contractors forums)*	✓	✓	✓	✓
EMPLOYEES	**Energy Queensland Employees**	Energy Queensland employees (all brands)	✓	✓	✓	✓
		Industry Partners	✓	✓	✓	✓

Some of our engagement activities are business-as-usual (e.g. the Queensland Household Energy Survey 2023, Talking Energy – the Queensland Energy Future Survey, and the ongoing Voice of Customer - Customer Satisfaction and Trust Measurement Program), but some were developed to meet the specific needs of the Regulatory Proposal engagement program (e.g. the RRG and the Voice of the Customer Panels, Customer Focus Groups and Network Pricing Working Group). Our Engagement Summary Report provides a comprehensive summary of the engagement activities undertaken.

The insights obtained from these engagement activities have not been considered by the business in isolation, but collectively, blending them to provide a more holistic view of what our customers and stakeholders have told us is important to them for consideration in our Regulatory Proposal. This is depicted in Figure 12. A summary of our Regulatory Proposal engagement program is provided in Figure 13.

Figure 12: Engagement Plan overview

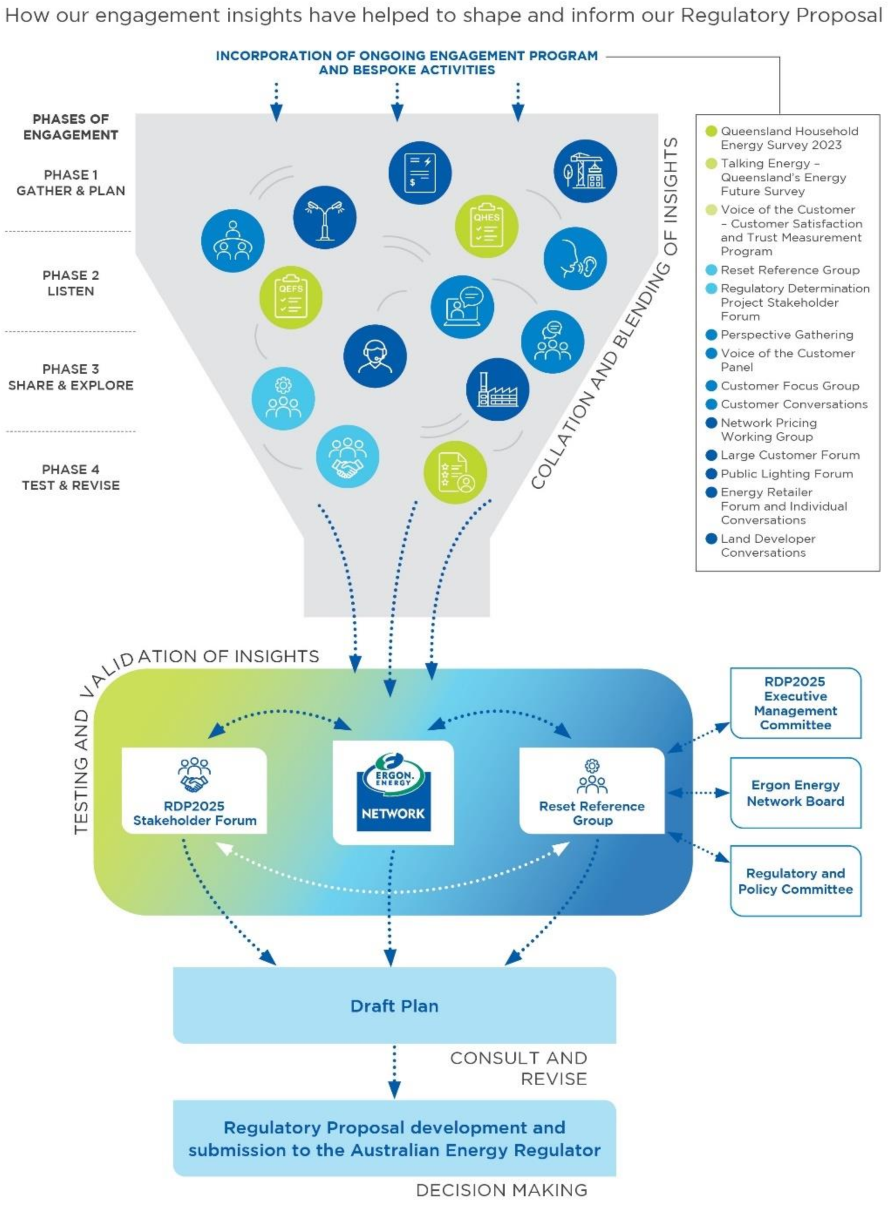


Figure 13: Summary of our Regulatory Proposal engagement program 'by numbers' 2022-23

Total numbers overall engagement reach

627 customers and stakeholders engaged

228 organisations engaged

171 engagement events or opportunities

396 hours of engagement

Customer Advocate and Stakeholder Engagement

3 RDP2025 Stakeholder forums with **74** participants

3 Agriculture forums with **22** participants

4 Customer and Community Council meetings with **35** participants

35 hours of engagement

Public Lighting Forum

14 online sessions

28 hours of engagement

68 local councils plus Department of Transport and Main Roads engaged

12 recommendations

1 Issues Paper, **6** fact sheets, **2** customer impact analyses, **1** smart lighting strategy

Reset Reference Group

5 members

25 project meetings

5 workshops

12 deep dives

105 hours of engagement

Network Pricing Working Group

12 workshops with **7** participants

46 hours of engagement

41 recommendations

Energy Retailer Forums & individual conversations

27 individual meetings

3 forums with **86** participants

26 hours of engagement

Customer conversations

11 small business customers

15 residential customers

26 hours of engagement

Voice of the Customer Panel

65 customer perspectives, **2** sessions over **6** hours

35 customers participated

42 hours of engagement

35 hours of deliberative discussions

12 recommendations

Customer Focus Group

2 focus group sessions with **30** participants

16 hours of engagement

6 key discussion topics

63 unique pieces of feedback

Large Customer Forum

7 individual meetings

4 forums with **109** participants

16 hours of engagement

Draft Plan

2 online webinar with **28** participants

17 public submissions

Social Media

Facebook reach **88,000** LinkedIn reach **25,500**

2,742 individuals and **741** organisations notified of the release of Draft Plan

3288 Talking Energy subscribers with **2.3k** site visits, **36** engaged visitors, **508** informed visitors, **1.1K** aware visitors

2.9 What customers have told us and how we are responding

Throughout our engagement process, we have consistently sought to establish a clear nexus between customers' sentiments and their desired outcomes. The iterative nature of our program has allowed us to make small, incremental changes to our positioning based on the information and feedback gathered from various engagement activities.

It is important to note that while each 'source of feedback' has its own limitations, no single piece of feedback was intended to compel us to make immediate changes to our Draft Plan or Regulatory Proposal. However, we have placed more weight on the deeper engagements with our Voice of the Customer Panel, Customer Focus Groups, and stakeholders attending the RDP2025 Stakeholder Forums, Public Lighting Forums, Large Customer Forums and Retailer Forums.

We have carefully reviewed and considered multiple sources of feedback over time to determine if there were clear and consistent directions or customer mandates that we should address to deliver a Regulatory Proposal that is genuinely consumer-centric. The expertise and insights provided by the RRG have been particularly valuable in shaping our engagement activities and informing our interpretation of the results.

The key themes and topics identified, and insights provided by our customers and stakeholders throughout our engagement activities, were reconfirmed through the feedback and submissions received on our Draft Plan that was released for consultation in September 2023. Customers and stakeholders were invited over a four week period to provide submissions via email or via a specially designed online questionnaire in response to a series of questions on our Draft Plan. On balance, the feedback and submissions on the Draft Plan correlated strongly with the views previously provided by customers and stakeholders on the energy challenges identified. The feedback and submissions received on the Draft Plan are available, where consent has been provided to publish by the submitter, on our Talking Energy website.

The Regulatory Proposal we present is a direct outcome of the preferences and insights of our customers, collected through in-depth and meaningful engagement, not only on the specific issues we engaged upon but on the sentiment they have provided on a range of issues. This document stands as a testament to the invaluable contributions and active participation of our customers and stakeholders, and we believe is a true reflection of their needs and preferences.

By giving due consideration to the input from various customer engagement initiatives and expert opinions, we are confident that our Regulatory Proposal aligns with the long-term interests of all regional Queenslanders. We remain committed to delivering outcomes that meet their needs and expectations.

A summary of how we are responding to the main themes and topics that our customers and stakeholders have identified as future energy challenges from their perspective, and of relevance to the issues we engaged them on, is provided in Table 10. They have shared their views on the energy challenges they face personally, as customers, and in their communities and provided insights on those and other matters we have addressed in this Regulatory Proposal.

Through our engagement activities we continue to hear the following key messages:

- safety should never be compromised
- electricity affordability is a concern for many customers – both from a cost-of-living and a business competitiveness perspective
- our customers want clear and concise information and access to energy usage data to help them make informed choices around their energy solutions with both pricing and non-pricing options available to manage energy costs

- there is significant interest in renewables and DER, with growing concerns around climate change fuelling customer and community expectations about the transition to a low carbon economy
- good customer service is expected, with transparency in customer service performance seen as essential to giving customers confidence in the services delivered
- our customers and communities value how we go about keeping the lights on, especially our response to severe weather events and other natural disasters, and
- the economic environment continues to bring 'energy inclusion and customer vulnerability' and 'economic resilience and jobs' to the foreground.

The customer and stakeholder insights on the varying themes and topics provided are addressed throughout this Regulatory Proposal in the relevant chapters where we indicate how they have influenced and evolved our thinking and decisions in relation to our investment and revenue recovery plans.

Table 10: What our customers have told us and how we are responding

Energy challenge or opportunity	What customers have told us	How we are responding
Energy affordability	Affordability of electricity is of paramount concern to customers from both a cost-of-living and cost-of-business perspective. The energy transition impacts on customers differently depending on their circumstances (e.g. 'haves' versus 'have nots'). Customers are interested in having greater choice and ways to reduce their energy consumption and therefore their energy costs. Electricity prices impact on the costs of doing business and can flow through into higher prices for goods and services provided by small and large businesses.	Affordability has been a key factor in setting our investment plans and is our foremost investment priority. We are focused on spending only what is prudent and efficient so that our customers pay no more than is necessary for their electricity supply. Our proposal responds to customer concerns on affordability by driving down controllable aspects of our expenditure program without compromising the safety or reliability of the network. We will reduce our revenue by applying a 1 per cent productivity factor to opex and capitalised overheads, and self-funding the capital spend above forecast for ICT for the last five years. We will continue to reform our network tariffs to provide opportunities to customers to benefit from low cost electricity in the middle of the day so all customers can benefit from the transition to renewable energy. We will provide new network tariff options for business customers with reduced time periods for peak pricing. We are committed to exploring network tariff and energy efficiency information campaigns and support mechanisms for customers into the future through collaboration with customers, stakeholders and industry partners.

Energy challenge or opportunity	What customers have told us	How we are responding
Transition to smart meters	Customers have told us they expect the industry as a whole to deliver simplicity, savings, value and choice, that rewards them for their role in the energy transition. Access to smart meter data can help provide energy usage information to customers to assist in making informed energy choices and managing their energy costs. Our customers have expressed a strong interest in how changes in the amount of revenue we recover will impact them through the network tariff they are assigned to by their retailer. Customers generally support the roll-out of smart meters by the end of 2030. However, the costs to maintain legacy 'basic' meters and associated services should be shared across all customers.	The transition to smart meters provides an opportunity for more efficient pricing structures. We will send more targeted and cost-reflective signals to customers so that the recovery of network investment is allocated to customers who use the network more in these peak periods (rather than those who do not). In line with feedback provided, we propose to share the costs of legacy metering services across all customers. This reduces the disproportionate cost burden on customers who will be the last to receive a smart meter, including vulnerable customers. We also propose to accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of 2025-30.
Increased risk of disruptions to our network due to natural disasters or cyber attack	The increasing frequency of major disruptive weather events and natural disasters is front of mind for customers. Customers are interested in our plans to ensure network resilience into the future.	Our network has long been required to deal with storm, flood and bushfire events. In recognition that our climate is changing, we will continue with a moderate increase in expenditure on our bushfire, flood and storm resilience programs. We will continue to mature our cyber security capability to reduce the risks of external threats to our network and data.
Uptake of new technologies and increasing export of electricity back into the grid	DER are seen as potential cost-saving and energy resilience building initiatives if utilised appropriately. Customers believe that the integration of DER into the network requires network pricing / tariff and other solutions to ensure customers can realise and maximise value from their DER investments. While investment in DER integration is expected and desired, customers who are unable to invest in and take advantage of DER should not be financially disadvantaged from energy costs associated with DER integration into the network. Availability and accessibility of energy and associated technologies is inequitable and there is concern around vulnerable customers not having access to innovative technologies or being able to benefit from the growth in renewable energy.	We have chosen a moderate pace of investment for integrating DER into our network to balance the desire of customers to take-up new technologies to export electricity with the needs of those customers who are unable to invest into new technologies. We will continue to reform our network tariffs to spread the benefits of renewable energy across our customer base with low or no network charges during the middle of the day. We expect that our dynamic connection offers will be widely available by July 2028, providing more options to customers around the volume of their exports from rooftop solar and battery storage.

Energy challenge or opportunity	What customers have told us	How we are responding
Customer service excellence	Customers expect good customer service to be a 'given' and do not believe schemes such as the AER's CSIS should be required to ensure good service is delivered. Customers want ease of interaction with us through their preferred communication channels and would like to see greater channel choice and flexibility. Timely and accurate information on a range of topics such as power outage information (planned and unplanned), and information on a range of issues, such as connecting DER is expected. Customers want greater transparency in customer service performance measures and such results to be made publicly available by means of holding us to account for the services we deliver. Where services do not meet minimum standards or expectations, service improvement plans should be made publicly available and progress regularly reported.	We support the feedback from customers and propose that the CSIS should not apply for 2025-30. Given our customers' strong views that we should not be rewarded for good customer service, we also propose that the customer service component (telephone answering) of the Service Target Performance Incentive Scheme should not apply. We will invest in our contact centre and online channels to provide information to customers on DER and energy efficiency. We have committed to review our customer service performance measures and metrics with input from our Customer & Community Council and publish these to improve transparency of our customer service levels.
Renewable and sustainable investments	Customers care about current and future environmental impacts and how investments to support the transition to net zero emissions may impact customers network prices. Investment in electric vehicles as part of our fleet should be at a 'slow and steady" pace as customers expressed concerns that electric vehicles at this time would not meet Ergon Energy Network requirements due to our vast geographical area with demanding terrain and the need for heavy duty vehicles.	In consideration of customer concerns around the cost of electric vehicles and availability of electric vehicle charging infrastructure, and noting customers affordability concerns, we will not proceed with transitioning a small portion of our fleet to electric vehicles.
Energy efficiency in public lighting	Customers supported the full deployment of LED lights by 2030 due to the financial and environmental benefits.	Our co-designed public lighting strategy provides for a transition to 100 per cent LED public lighting by 2030.

2.10 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Customer and Stakeholder Engagement Strategy	2.01	Ergon - 2.01 - Customer and Stakeholder Engagement Strategy - November 2023 - public
Customer and Stakeholder Engagement Plan	2.02	Ergon - 2.02 - Customer and Stakeholder Engagement Plan - January 2023 - public
Engagement Summary Report	2.03	Ergon - 2.03 - Customer and Stakeholder Engagement Summary Report - December 2023 - public

3.
Investment Priorities for 2025-30

Key messages:

- Our customers have made it clear that affordability of electricity is their paramount concern.
- Our customers have also made it clear that they expect us to maintain reliability, resilience, service and safety.
- These priorities are reflected in our proposed five-year investment plans which are aimed at supporting a higher penetration of renewables and meeting the increased demand from economic, jobs and population growth.

3.1 Our investment priorities

Our customers have told us that electricity affordability is their paramount concern from both a cost-of-living and cost-of-business perspective and that they are interested in having greater choice and ways to reduce their consumption and energy costs. The current economic environment has also led to concerns about the ability of particular customers to respond to the changes taking place in the industry, with energy inclusion and customer vulnerability being front of mind for some customers. There is a view that we need to ensure that everyone benefits equitably from solar and other emerging technologies and that vulnerable segments of the community should not be left behind.

Notwithstanding that affordability of electricity supply is their primary concern, customers also consider that safety should never be compromised and that the existing balance between cost and reliability is appropriate. Regional Queensland communities value how we go about keeping the lights on, especially in our response to severe weather events and other natural disasters.

Fuelled by concerns about climate change, customers are taking a greater interest in renewables, battery storage and electric vehicles. There is an expectation that Ergon Energy Network will facilitate customer opportunities and the integration of greater volumes of DER into the network. However, there is also an expectation that we should do this without creating risks to network security, supply quality or performance.

Based on customer feedback from our business-as-usual and targeted engagement activities and taking into account our external environment and the key challenges and opportunities Ergon Energy Network and our customers will be facing in 2025 and beyond, we have developed four investment priorities for the next regulatory control period. These priorities are set out in Figure 14.

Figure 14: Our investment priorities

3.1.1 Investment priority 1: Deliver electricity services in the most efficient and affordable way

In delivering our investment plans, we will aim to invest only what is necessary to meet the energy needs of regional Queensland, and in so doing minimise price increases for our customers. However, we do not want to be in a position in the future where we place the burden to pay on the next generation of customers because we have not acted today. Therefore, we must strike the right balance between investing into the network to provide clean, reliable and smart electricity to homes and businesses and addressing customers' affordability concerns. To that end, we are committed to providing cost-effective and efficient services that allow us to keep pace with the energy transition and deliver affordable electricity supply to our customers.

To minimise bill impacts for our customers, we will:

- **Strengthen oversight of network investments to ensure we continue to spend only what is prudent and efficient to meet customer needs now and into the future**

  To ensure the prudency and efficiency of our investments, we are committed to having a robust governance framework and management tools and processes to enable informed decision-making. In accordance with this objective, an external review of our existing investment management framework has recently been undertaken and we are currently making changes based on best practice recommendations. These changes will include greater oversight of network investments by our Board Regulatory and Investment Committee.

- **Apply a 1 per cent productivity factor to operating expenditure and capitalised overheads**

  In recognition of the fact that affordability is a key concern for our customers, we have chosen to apply a higher productivity factor of 1 per cent to our opex than the AER's standard 0.5 per cent. We have also chosen to apply a 1 per cent productivity factor to capitalised overheads forecasts for the five-year period, notwithstanding the fact that the AER does not apply a productivity factor to capitalised overheads. We have chosen to apply these productivity factors to drive efficiency improvements and cost savings in how we deliver electricity to our customers.

- **Self-fund the non-network ICT capex above the AER allowance**

  In recognition of our customers' affordability concerns, we have looked for ways to reduce our revenue for the next regulatory control period. Over the last five years, we have spent higher than forecast for our non-network ICT, though overall we are within the AER allowance for capex. As discssed in our Draft Plan, to provide an immediate reduction to our forecast revenue, we have decided to self-fund the difference between our non-network ICT capex and the AER-accepted ICT capex forecast for the last five years.

The ICT and productivity factor initiatives will result in a revenue reduction of $142 million (or 2 per cent) over the 2025-30 regulatory control period.

3.1.2 Investment priority 2: Ensure the safety and reliability of our ageing network

We understand that as cost-of-living pressures increase for many regional Queenslanders, prudent investment plans are required to provide a secure and reliable energy supply while minimising operating and capital costs. At the same time, Ergon Energy Network must continue to ensure the safety of our customers, communities and employees by managing the risks associated with the electricity network and meeting safety obligations.

While we are committed to maximising value from the network for the benefit of our customers and communities, our existing assets are ageing and at an increasing risk of failure. Across regional Queensland, Ergon Energy Network has invested in refurbishment and replacement works to address the performance challenges of an ageing network and meet community safety and reliability expectations. These works include targeted pole and conductor replacements in older sections of the network.

As a consequence, we have overspent our capex allowance for the 2020-25 regulatory control period. Further, these essential works, which are critical to the future safety and reliability of our distribution network, will continue into the 2025-30 regulatory control period requiring similar levels of expenditure.

The key programs of work driving expenditure on our network are described below:

- **Pole replacement and reinforcement**

  Ergon Energy Network's distribution network consists of approximately one million power poles, many of which are significantly aged. Pole failures can result in network outages and are a safety risk to our people and customers. Ergon Energy Network has been progressively replacing and reinforcing all poles that are found to be in poor condition to reduce the risk of failure.

- **Replacement of copper conductor**

  Ergon Energy Network owns and maintains approximately 145,000 kilometres of overhead powerlines. Conductor failure, such as fallen powerlines, is a serious safety hazard and results in loss of power supply to our customers and communities. Our replacement program is focused on the populated coastal regions with copper conductor, which becomes brittle with age and prone to failure due to corrosion and mechanical fatigue.

- **Substation refurbishment**

  Many of our substations have components that are over 60 years old and are at risk of failing and causing safety risks and reliability issues. Our substation refurbishment program will target the replacement of substation assets that are at the end of their expected life to ensure the achievement of safety, quality and reliability performance outcomes.

3.1.3 Investment priority 3: Provide a well-integrated and resilient electricity network to meet future needs

As a Government Owned Corporation, Ergon Energy Network is a key partner in delivering the policies set by our shareholder, the Queensland Government. As such, we will be supporting the delivery of the State's pathway for accelerating the transition to renewable energy to reduce emissions. This energy transformation focuses on developing solar and wind generation and battery and pumped hydro energy storage and ensuring there is supporting infrastructure to transport renewable energy to all households and businesses across the region.

Our priority in supporting the energy transformation will be to continue to provide reliable and affordable electricity to our customers while ensuring we have a well-integrated, smart, and resilient electricity system to deliver our State's clean energy targets and support employment, population, and economic growth. This will require investments in new technology, resources, and network capability.

The key areas influencing our investment plans for providing a well-integrated and resilient electricity network are discussed below:

- **Support growth in demand and connections**

  In line with the transition to a clean energy future and the expected growth in regional Queensland's economy and population, our distribution network will need to provide the electricity infrastructure to support more connections and household and business demand for solar systems, batteries, and electric vehicles. This will require us to invest capital to connect new customers to the network, upgrade our network to respond to the growth in demand, and ensure the efficient integration of renewables and clean energy, while continuing to keep the lights on.

- **Improve the resilience of our network**

  Ergon Energy Network has strong experience in responding to the impacts of disruptive events on our network, particularly weather-related events such as cyclones, storms, bushfires, and floods. To meet the performance expectations of our customers and communities, we must continue to invest in the resilience of our network to minimise the impact of future disruptive events on the continuity of electricity supply. While our long experience in responding to climate-related events means we have a network that is well-prepared, we will be undertaking works to protect critical network infrastructure and improve resilience in targeted areas, including raising assets in flood zones and installing covered conductor, sparkless fuses and pole wraps in bushfire prone areas. Further, given recent cyber-attacks on other essential service providers, we are also maturing our cyber security capability to protect the system and customer data as we shift to a smarter and more integrated network, and ensure the security of our infrastructure.

- **Increase access to network information**

  To expand our capacity to support growing volumes of DER we need more timely data and information about our distribution network and the resources connected to it. We can use this data to better manage the network by dynamically varying import and export limits over time and location, based on the available capacity of the local network or power system as a whole. This will enable more DER to be connected at a lower cost. Having greater access to timely data and information to determine the electrical status of the low voltage network will also improve our ability to identify and respond to reliability issues.

- **Deploy SAPS**

  Providing electricity via traditional poles and wires to customers at the fringe of the national grid or in remote or hard to access locations is increasingly more inefficient and costly. With the rapid advancement in technology and decrease in costs of off-grid supply technologies, it is important for Ergon Energy Network to consider alternative supply options, such as SAPS to drive improved customer outcomes from both a cost and reliability perspective. Through the next regulatory control period Ergon Energy Network will continue to identify and rollout SAPS in locations that make sense. This will be supported by other fringe-of-grid innovations and trials, such as solar pumps and microgrids.

3.1.4 Investment priority 4: Facilitate customer opportunities in the transition to renewable energies

Our customers are increasingly concerned with climate change and moving towards a low carbon economy in a way that is fair and equitable to everyone. Customers expect us to invest in the network to allow for the integration of DER and to develop solutions that enable them to maximise value from their investments. However, at the same time, there is concern that customers who are unable to invest in and take advantage of DER should not be financially disadvantaged.

In supporting our customers to transition to a net zero emissions future, we must proactively manage our distribution network to facilitate higher customer uptake of DER, such as solar panels, batteries and electric vehicles. One of the ways this will be achieved is through Energy Queensland's new role as the Distribution System Operator for regional Queensland.[6] This role will allow the dynamic operation of two-way power flows in the distribution network within technical limits and optimise available DER. Our customers will be able to leverage the many benefits of digital transformation and DER to manage their energy usage and maximise the benefits of their investments, while also allowing us to leverage these technologies to manage our network assets more efficiently.

We must develop strategies to manage the rising challenge of low energy demand during the day which can cause power quality issues that can be harmful to customer appliances as well as to the network. In regional Queensland, due to the high volume of solar generation installed, we are already seeing new daytime lows in minimum demand creating reverse power flows in localised parts of our network and stability concerns that could intensify the risk of blackouts in the coming years. While managing the challenge of minimum demand is a key concern for the network, we are committed to developing solutions that will enable customers to get the best value from their systems and maximise the use of renewable energy.

All customers will benefit from greater integration of renewable energies into the electricity system through lower overall system costs. However, while owners of DER will have the opportunity to export electricity or participate in energy markets to reduce their bills, not all customers have the ability to invest in and take advantage of the benefits of DER. We are therefore committed to developing solutions that enable those customers to reduce their electricity costs so that they are not left behind in the renewable energy transition.

[6] Queensland Government, *Queensland Energy and Jobs Plan,* September 2022, p. 37.

The key areas we are focusing on to facilitate customer opportunities in the transition to renewable energies for the 2025-30 regulatory control period are discussed below:

- **Implement new network tariff structures**

  While network tariffs play an important role in improving price equity across all customer groups, they also send price signals intended to improve network utilisation and avoid or defer future investment in congested parts of the network. For example, residential and small non-residential customers with access to a smart meter are currently assigned to a demand-based network tariff that encourages them to avoid the evening peak period and have the option to select a ToU solar soak tariff with price incentives to use more energy during the day when the sun is shining. For those that do not have the means or space to install DER, a solar soak tariff allows these customers to benefit from the increase in solar energy through lower priced energy in the middle of the day.

  For the next regulatory control period we see further opportunities to explore solutions that increase the efficiency of our tariffs to encourage our customers to use the network in ways that limit the need for future network augmentation and reduce the prices they pay for electricity.

- **Offer dynamic connection agreements**

  Dynamic connection agreements will allow households and businesses to access new and emerging energy technologies as they become available. Dynamic connections seek to give customers choice about connecting the energy resources they want, while minimising impacts to the grid by communicating varying import and export limits to the customer's energy resources. Dynamic connections will allow more households to install rooftop solar and batteries and take advantage of the associated cost benefits, while improving outcomes for everyone.

- **Expand our demand management program**

  We will continue to build on our long-standing and well-established demand management program to lower network augex, reduce customer bills and provide a greater balance between customer demand and renewable generation. Our expanded demand management program, which will continue to include our existing air-conditioning and hot water load control programs, will work alongside dynamic connections, cost-reflective tariffs, and battery energy storage to ensure we can effectively integrate renewables and the 'electrification of everything', while continuing to ensure affordable, safe, and reliable operation of our network.

- **Continue our collaboration with customers and stakeholders**

  The energy landscape is rapidly evolving, and our customers' needs are changing in response to technological, economic and environmental factors, and cost-of-living pressures. To ensure that our plans are meeting the needs and preferences of all our customers, we will continue to closely collaborate with customers and other stakeholders throughout the regulatory control period. We will also continue to advocate for industry-wide solutions to support all customers through this transition, including measures aimed at increasing awareness of energy efficiency, financial support available (e.g. rebates), and potential benefits from investing in DER.

3.2 How this differs from our Draft Plan

Feedback from our customers, stakeholders and the RRG was that affordability is of utmost concern and we need to prioritise delivering electricity as efficiently as possible.

While respondents to our Draft Plan generally supported our investment priorities, we did receive some feedback that there should be a stronger focus on affordability. Notwithstanding that affordability has always been an overarching focus for us, we acknowledge that it requires greater prominence in our Regulatory Proposal. Therefore, we have made affordability our leading investment priority for 2025-30.

4.
Demand, Energy Delivered and Customer Forecasts

Key messages:

- System peak demand is expected to grow by 1 per cent annually, and is a key driver of our forecast augex.
- The population in regional Queensland is expected to grow and is projected to result in an average increase in customer numbers of 0.8 per cent annually.
- The continued growth in solar PV installations is changing the shape of the load profile, reducing energy delivered and amplifying the impacts of minimum demand.
- Although uptake of electric vehicles is expected to increase significantly and contribute to the system peak demand, it is growing from a low base and is only expected to accelerate in the latter part of the regulatory control period.

4.1 Overview

Forecasting is a critical element of our network planning and is essential to the development of our investment plans. Electricity demand forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply-side or customer-based solutions.

This chapter outlines the key forecasts that have influenced our Regulatory Proposal for the 2025-30 regulatory control period, including:

- **System peak demand** – a measure of the total volume of electricity required to be available for a customer at a single point in time (in kilowatts (kW)). System peak demand is used to identify future capacity constraints, a key driver of network augex
- **Minimum demand (or negative peak demand)** – a measure of when electricity usage is at its lowest and the export of energy from rooftop solar systems is at its highest. Minimum demand requires us to deploy solutions that will minimise impacts on the network and is a key driver of demand management initiatives
- **Energy delivered** – a measure of the total energy used by all customers over a period of time (in kilowatt hours (kWh)). Energy delivered is relevant to setting network prices
- **Customer numbers** – a projection of the number of customers expected to be connected to the network (closely linked to forecast population growth). Customer numbers form the basis of both demand and energy forecasts and is a key driver of our connex, and
- **Growth in DER** – a projection of growth in the uptake of electric vehicles, solar PV systems and battery energy storage systems. Growth in DER is a key driver of our capex program and feeds into our DER Integration Strategy (Attachment 5.6.01).

In summary, we project that for the 2025-30 regulatory control period:

- continued growth in the network will result in system peak demand rising by an average of 1 per cent annually
- the increasing penetration of rooftop solar will cause minimum demand to fall by an average of 100MW annually
- energy delivered will decrease by an average of 0.2 per cent annually
- annual average growth in customer numbers will be around 0.8 per cent in line with expected population growth in Queensland
- electric vehicle volumes will increase from between 41,000 units and 118,000 units by 2030 (depending on the rate of uptake) as there is greater choice and cost parity with conventional vehicles
- solar PV uptake is likely to remain strong and could grow by up to 10.3 per cent annually, and
- battery energy storage systems will potentially increase by 35.8 per cent annually as they become more economically viable.

4.2 System peak demand

System peak demand, also known as 'maximum demand', is the highest rate of energy use that occurs when the community's electricity use is at its highest. This usually occurs between 4pm and 9pm on our hottest summer days. System peak demand is a key driver of network augex.

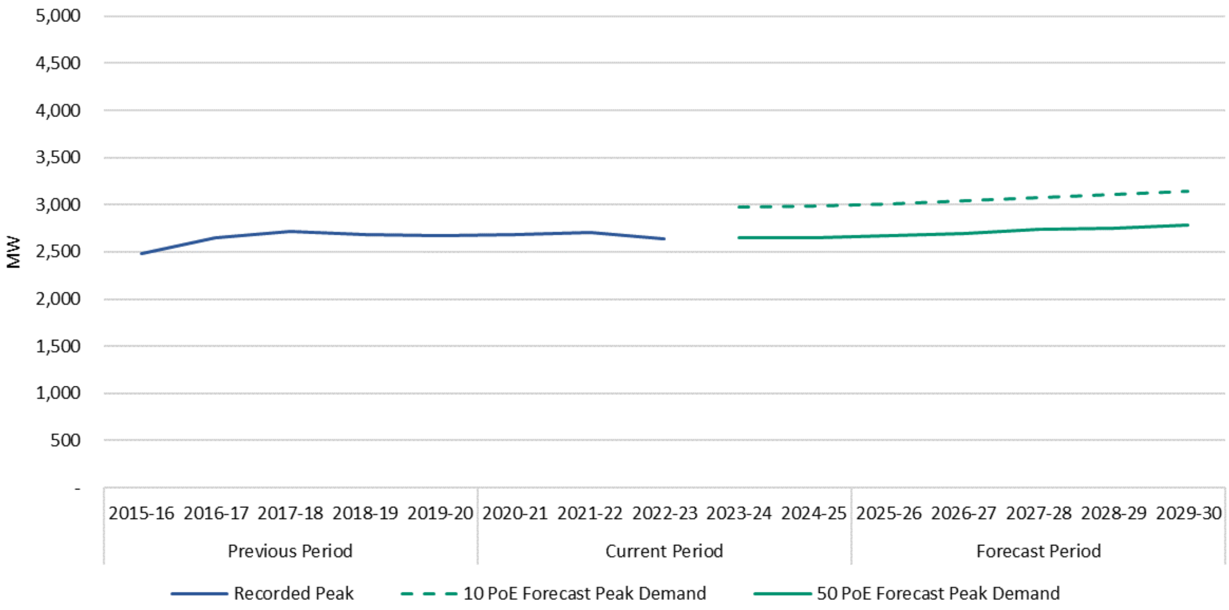
In preparing peak demand forecasts for network planning purposes, the Probability of Exceedance (PoE) is used as a measure for the natural variation in peak demand due to factors such as (but not limited to) the weather, with:

- a 10 per cent PoE forecast being the extreme season benchmark where maximum demand is high and only expected to be exceeded once every 10 years, and
- a 50 per cent PoE forecast being an average season benchmark which is expected to be exceeded once every two years.

Ergon Energy Network reviews and updates our 10-year summer peak demand forecasts after each summer season and each new forecast is utilised to identify emerging network limitations in both the sub-transmission and distribution networks.

Figure 15 shows actual peak demands for the past seven years, along with our 50 per cent and 10 per cent PoE medium scenario forecasts for the period through to 2030. The annual average growth in system peak demand is forecast to be around 1 per cent during the 2025-30 regulatory control period.

Figure 15: Actual and forecast system peak demand



The data supporting Figure 15 is provided in Table 11 and Table 12.

Table 11: Historical system peak demand

	Previous Period					Current Period		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Recorded peak demand (MW)	2,481	2,651	2,716	2,689	2,677	2,688	2,702	2,637

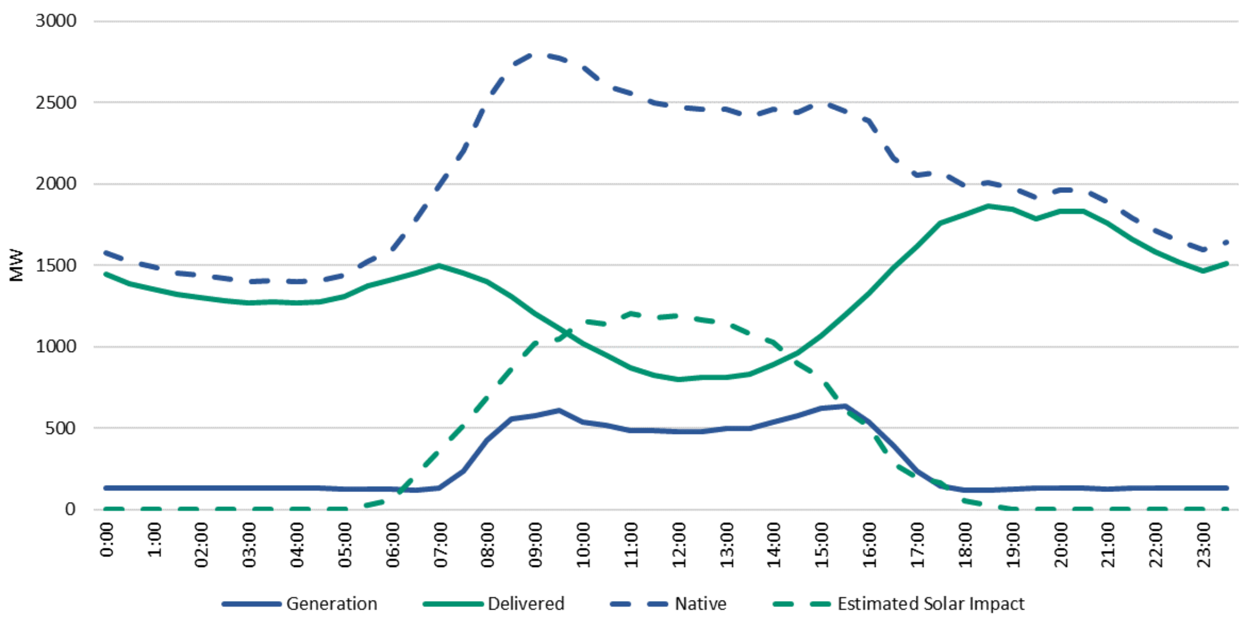
Table 12: Forecast system peak demand

	Current Period		Future Period				
	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
10 PoE forecast peak demand (MW)	2,970	2,982	3,008	3,043	3,077	3,114	3,143
50 PoE forecast peak demand (MW)	2,647	2,645	2,667	2,698	2,741	2,754	2,783

4.3 Minimum demand

In the early years of solar PV, export from solar installations had minimal impact on our distribution network. However, the scale of solar PV generation present today is changing the shape of our network load profile (refer to Figure 16), resulting in the new challenge of managing minimum (or negative peak) demand.

Figure 16: Impact of solar PV on the daily load profile

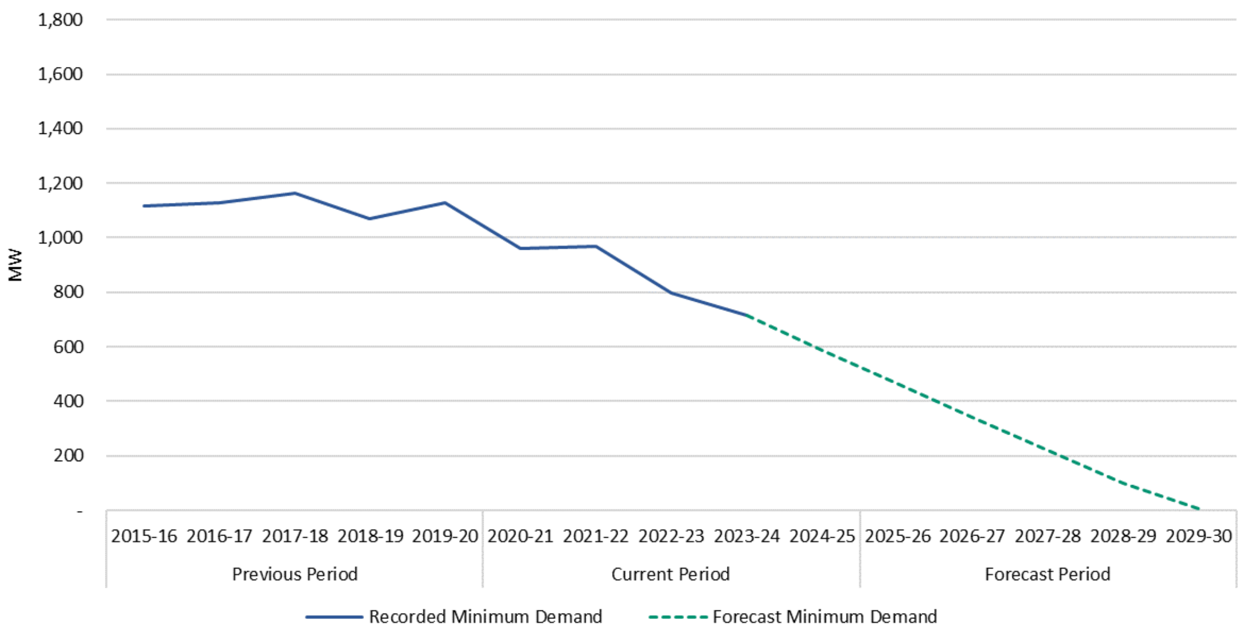


Minimum demand is typically caused when rooftop solar and storage matches or exceeds demand on the network. This usually happens between 10am and 2pm on clear, sunny days during spring and autumn, particularly on weekends or public holidays. As minimum demand continues to fall, it presents a different set of challenges for our network in managing reverse flows and associated power quality and stability issues.

With the increasing penetration of rooftop solar, minimum demand is expected to fall by an average of 100MW annually.

Figure 17 shows Ergon Energy Network's historical minimum demand along with our base scenario minimum demand forecast for the period through to 2030.

Figure 17: Actual and forecast minimum demand



The data supporting Figure 17 is provided in Table 13 and Table 14.

Table 13: Historical system minimum demand

	Previous Period					Current Period		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Recorded minimum demand (MW)	1,117	1,128	1,165	1,070	1,128	961	969	799

Table 14: Forecast system minimum demand

	Current Period		Future Period				
	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Forecast minimum demand (MW)	714	586	465	341	220	101	7

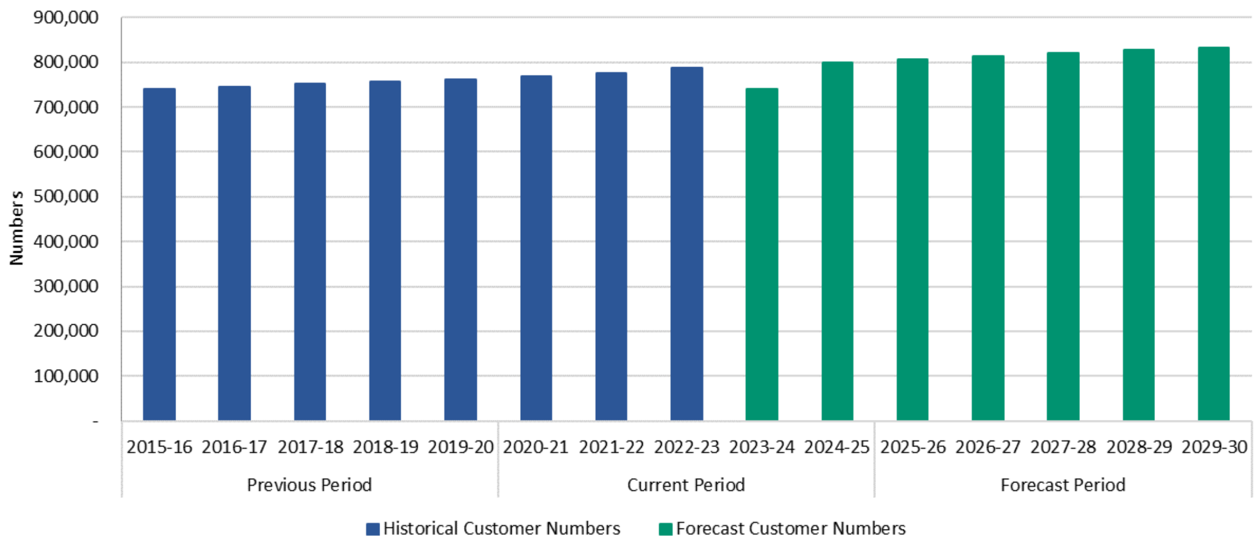
4.4 Customer numbers

Our customer number forecast forms the basis of both the demand and energy forecasts and is an input into our connex forecast.

Population growth in regional Queensland drives the volume of new home and business customer connections to our network. The growth in Queensland's population has been strong since the Covid-19 pandemic, with 2.1 per cent year-on-year increases to the June 2023 quarter. It is expected that Queensland will continue to see increased interstate and overseas migration levels in the 2025-30 regulatory control period.

Figure 18 shows Ergon Energy Network's historical connected customer count for the past eight years along with our base scenario customer number forecast for the period through to 2030. The annual average growth for customer numbers is forecast to be around 0.8 per cent during the 2025-30 regulatory control period.

Figure 18: Historical and forecast customer numbers



Note: Historical customer numbers are as per the relevant Economic Benchmarking Regulation Information Notice (table 3.4.2). Customer numbers represent the average number of active and de-energised National Meter Identifiers (NMIs) on the network in the relevant financial year, calculated as the average number of NMIs on the last day of the prior financial year and on the last day of the relevant final year. Each NMI has been counted as a separate customer.

The data supporting Figure 18 is provided in Table 15 and Table 16.

Table 15: Historical customer numbers

	Previous Period					Current Period		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Customer numbers	739,353	745,505	752,141	757,726	762,303	767,583	776,533	786,523

Table 16: Forecast customer numbers

	Current Period		Future Period				
	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Customer numbers	793,444	800,103	806,762	813,559	820,226	826,552	832,756

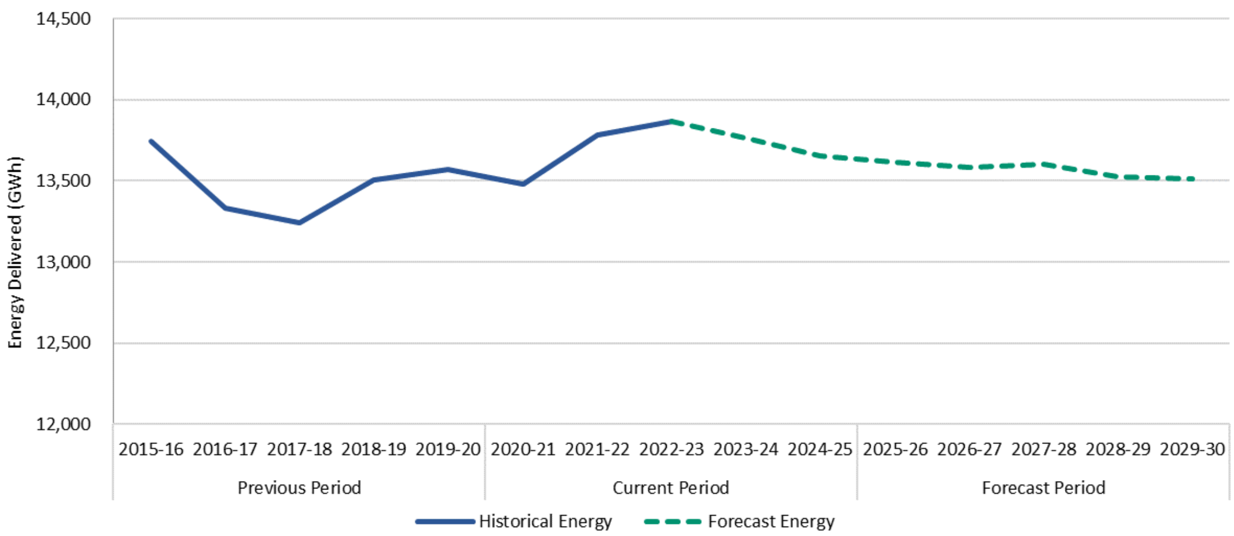
4.5 Energy delivered

Although the energy delivered forecast does not drive capex requirements, it is utilised to determine the forecast price path associated with the revenue cap. The energy forecast is calculated at a residential and small business level due to the different consumption behaviours of each group and their sensitivity to weather. They are then aggregated to provide a system level view.

With increasing penetration of rooftop solar panels, it is expected that energy delivered across the network will continue to fall in the short-term, before recovering with an increase in electric vehicle adoption in the latter years of the forecast.

Figure 19 shows our historical energy delivered for the past eight years along with our base scenario energy delivered forecasts for the period through to 2030. The annual average growth in energy is forecast to fall by around 0.2 per cent during the 2025-30 regulatory control period.

Figure 19: Actual and forecast energy



The data supporting Figure 19 is provided in Table 17 and Table 18.

Table 17: Historical energy delivered

	Previous Period					Current Period		
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Energy delivered (GWh)	13,747	13,332	13,243	13,504	13,567	13,477	13,780	13,868

Table 18: Forecast energy delivered

	Current Period		Future Period				
	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Energy delivered (GWh)	13,760	13,652	13,618	13,585	13,599	13,525	13,513

4.6 Distributed energy resources

The amount of DER (i.e. solar PV, electric vehicles and battery energy storage systems) in the network is growing rapidly and changing the way customers use electricity. In 2023, we engaged an external consultant, Blunomy, to assist us in developing DER forecasts for the various technological uptake scenarios - fast, medium and slow - along with predicted profile simulations for both behind-the-meter battery energy storage systems and electric vehicles.

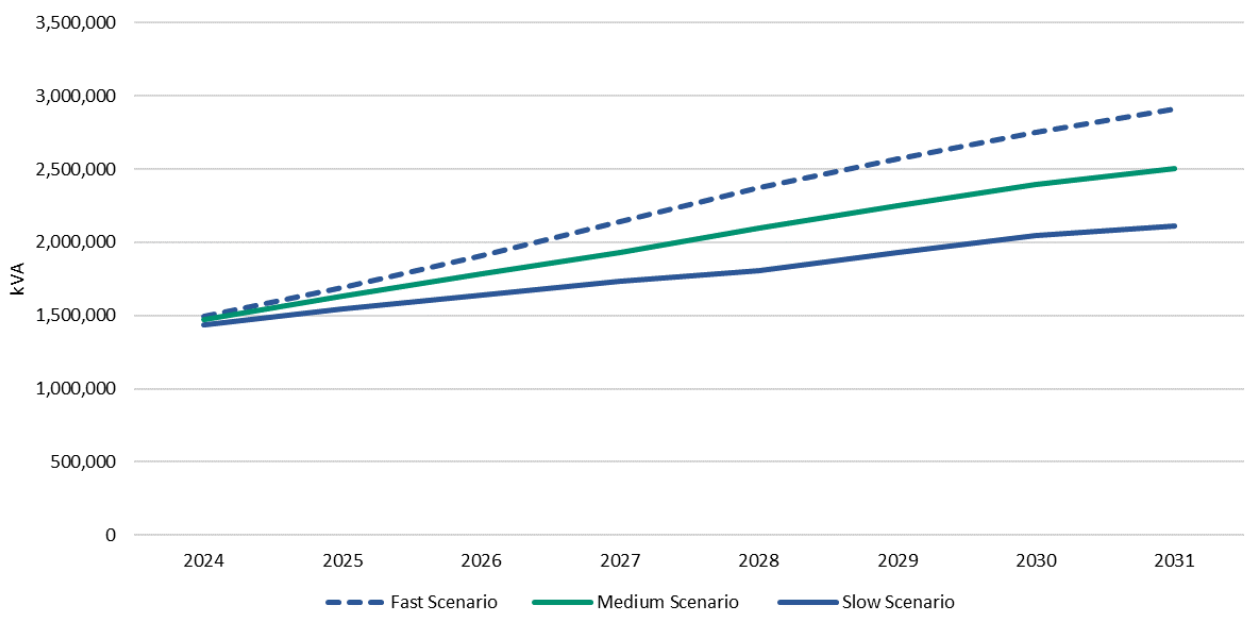
A summary of our forecasts is provided below, with more detail available in our 2023 Strategic Forecasting Annual Report which is available on our website.[7]

4.6.1 Solar PV

Our solar PV forecast is a key input in developing our demand and energy forecasts. The expected continuing strong uptake has a material impact on our demand and energy delivered forecasts. We forecast that solar PV could grow by up to 10.3 per cent annually.

Figure 20 shows the scenario-based forecast for solar PV capacity (inverter).

Figure 20: Solar PV forecasts by scenario (by calendar year)



The data supporting Figure 20 is provided in Table 19.

Table 19: Solar PV forecasts by scenario (by calendar year)

	2024	2025	2026	2027	2028	2029	2030	2031
Fast Scenario (kWh)	1,495,848	1,688,268	1,907,139	2,143,654	2,373,885	2,571,596	2,752,963	2,913,044
Medium Scenario (kWh)	1,474,034	1,634,910	1,784,875	1,933,052	2,095,364	2,252,515	2,397,029	2,505,644
Slow Scenario (kWh)	1,433,019	1,543,449	1,642,623	1,730,580	1,806,944	1,930,590	2,044,309	2,113,196

[7] Strategic Forecasting Annual Report 2023 (ergon.com.au).

4.6.2 Electric vehicles

Electric vehicle forecasts are important for energy and maximum demand forecasts, as well as predicting changes in the load profile.

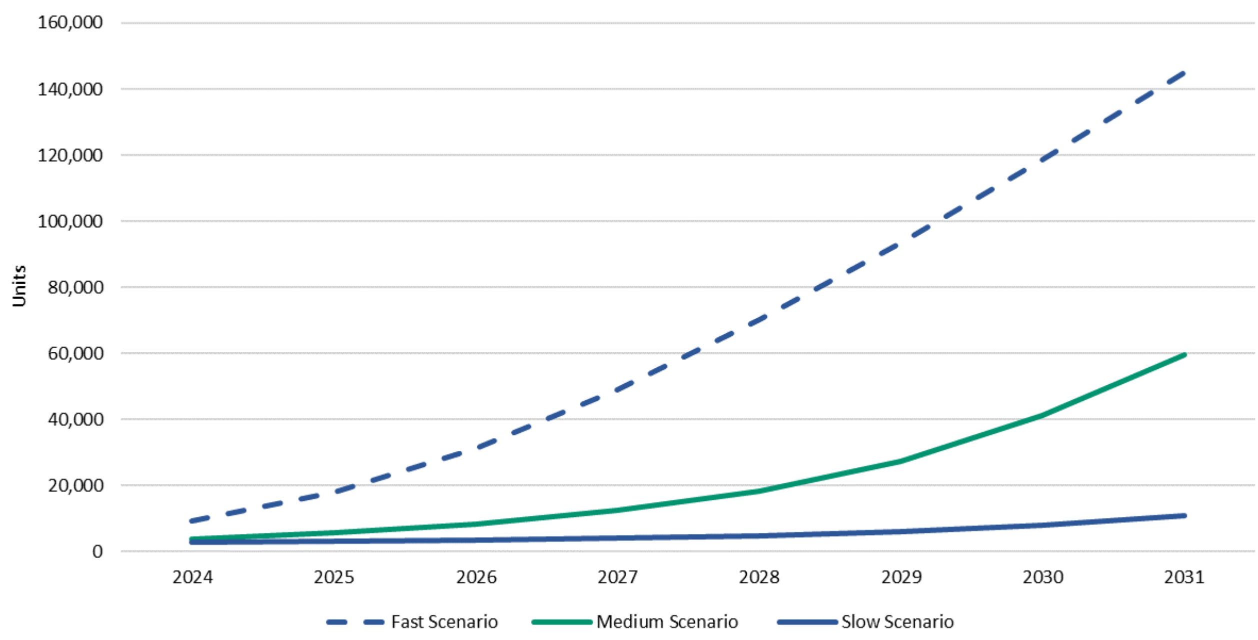
Although the uptake of electric vehicles and plug-in hybrid electric vehicles has been historically low due to a combination of factors, including high initial cost and limited availability of vehicle types, it is anticipated that the adoption of electric vehicles is likely to have a significant impact on peak demand and energy towards the end of the forecast period.

As electric vehicle adoption is still in the early stages, charging behaviours and patterns are yet to be observed in the mass market environment. Most electric vehicle users are early adopters who are conscious of and knowledgeable in the efficient use of both their vehicles and energy, and do not necessarily represent the charging behaviours of the wider community of users.

Depending on the rate of uptake, there is the potential that the number of electric vehicles in regional Queensland will increase by between 41,000 units and 118,000 units by 2030 as there is greater choice and cost parity with conventional vehicles.

Figure 21 shows three scenario forecasts for electric vehicle uptake in regional Queensland.

Figure 21: Electric vehicle forecasts by scenario (by Calendar Year)



The data supporting Figure 21 is provided in Table 20.

Table 20: Electric vehicles forecasts by scenario (by calendar year)

	2024	2025	2026	2027	2028	2029	2030	2031
Fast Scenario (units)	9,190	17,887	31,271	49,076	70,065	93,361	118,400	144,827
Medium Scenario (units)	3,852	5,684	8,439	12,387	18,280	27,499	41,348	59,683
Slow Scenario (units)	2,702	3,106	3,524	4,086	4,886	6,100	7,988	10,792

4.6.3 Battery energy storage systems

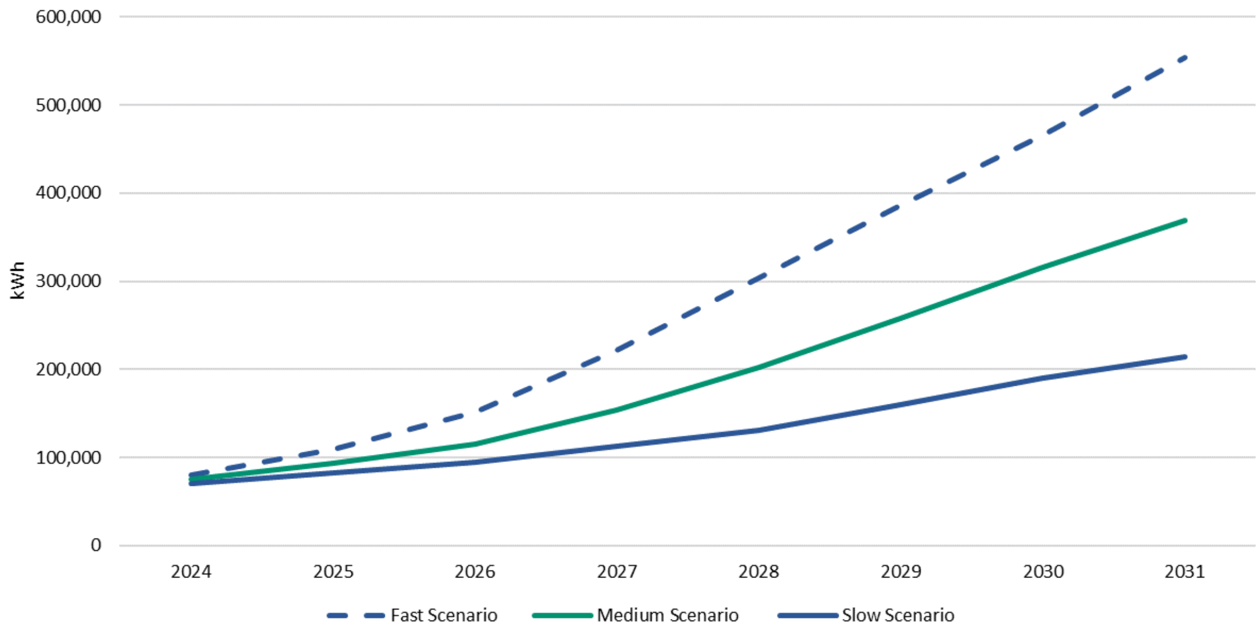
Battery energy storage system forecasts are important for predicting changes in the load profile, particularly at a local level.

If managed effectively, the storage systems can be utilised to charge during sunlight hours when solar PV generation is high to offset the impact of minimum demand, and discharge during peak times to offset peak demand. However, due to the high initial capital cost and consequent low uptake, it is unlikely that behind-the-meter battery energy storage systems will have a significant impact on our network in the short-term. Nevertheless, customer interest in batteries will continue to increase as the technology becomes more economically viable.

Our forecasts indicate that there is the potential for the number of battery energy storage systems to increase by 35.8 per cent annually.

Figure 22 provides the most recent non-network forecasts.

Figure 22: Battery energy storage system forecasts by scenario (by calendar year)



The data supporting Figure 22 is provided in Table 21.

Table 21: Battery energy storage system forecast by scenario (by calendar year)

	2024	2025	2026	2027	2028	2029	2030	2031
Fast Scenario (kWh)	79,988	109,377	151,481	221,314	303,805	385,641	466,086	553,299
Medium Scenario (kWh)	75,065	92,944	115,372	154,133	202,352	257,607	315,759	368,936
Slow Scenario (kWh)	70,824	82,032	94,444	112,333	130,688	159,748	189,686	214,284

4.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
System Peak Demand Forecasting Methodology Review	4.01	Ergon - 4.01 - ACIL Allen - System peak demand forecasting methodology review - September 2022 - public
Review of Energy Forecasting Methodology	4.02	Ergon - 4.02 - ACIL Allen - Review of energy forecasting methodology - February 2023 - public
Distributed Energy Resource Forecast for Energex and Ergon Energy Network	4.03	Ergon - 4.03 - Blunomy Distributed Energy Resource Forecasts - May 2023 - public
Demand, Energy Delivered and Customer Forecasting	4.04	Ergon – 4.04 – Demand, Energy Delivered and Customer Forecasting – December 2023 - public

5.
Capital Expenditure

Key messages:

- To meet customer expectations we are focused on driving down the controllable aspects of our capex program without compromising the safety or reliability of the network.
- Our forecast capex for the 2025-30 regulatory control period is $5,805 million. This represents an increase of 20 per cent relative to our capex for the current regulatory control period.
- Customer views around maintaining our current levels of reliability and safety of the network have informed the development of our capital investments.
- To address customers' affordability concerns, all capex investments were subjected to rigorous analysis and scrutiny to ensure that our proposal reflects the best value for customers.
- Our capex forecast contributes to the return of capital and regulatory deprecation building blocks that form part of our revenue requirement.

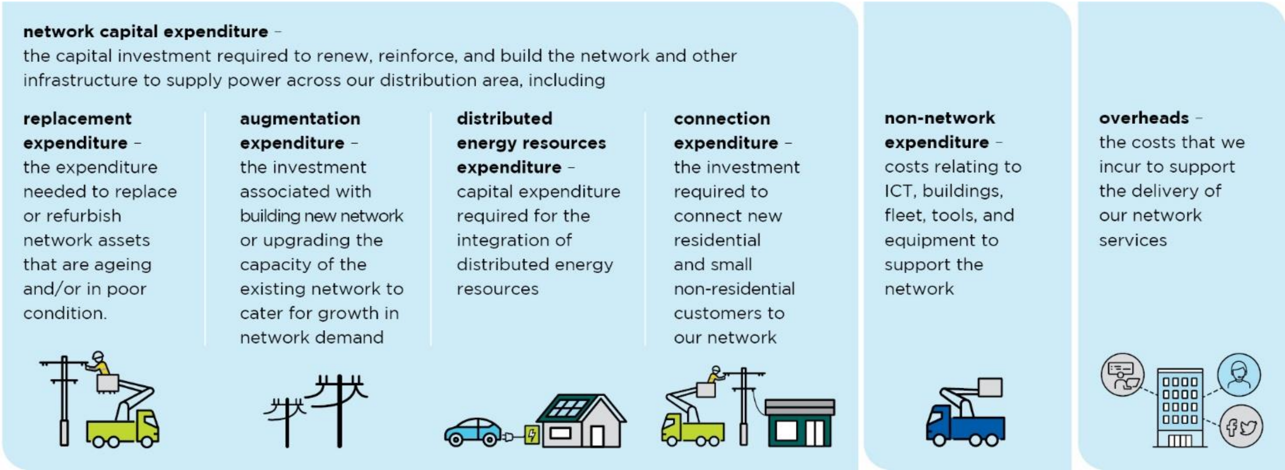
5.1 Overview

Our customers and communities expect Ergon Energy Network to maintain the reliability, resilience and safety of our network, while meeting the needs of a growing economy and population, and facilitating opportunities in the renewable energies transition.

Many of our regions are growing steadily and the demand for power is increasing, particularly in the larger regional centres. We must invest in our network to ensure there is enough capacity to supply every household and business on the days when electricity demand is at its maximum, no matter where they are located across our distribution area. In addition, we need to have enough capacity to accept the growing distributed solar energy that our customers export each day. We must also continue to invest in the safety and performance of our network and be ready to respond to emergencies and major weather events, as well as invest in the business systems and related infrastructure required to ensure that our daily operations run smoothly and efficiently. At the same time, in response to customer concerns about affordability, we are focused on driving down the controllable aspects of our capex program without compromising the safety or reliability of the network.

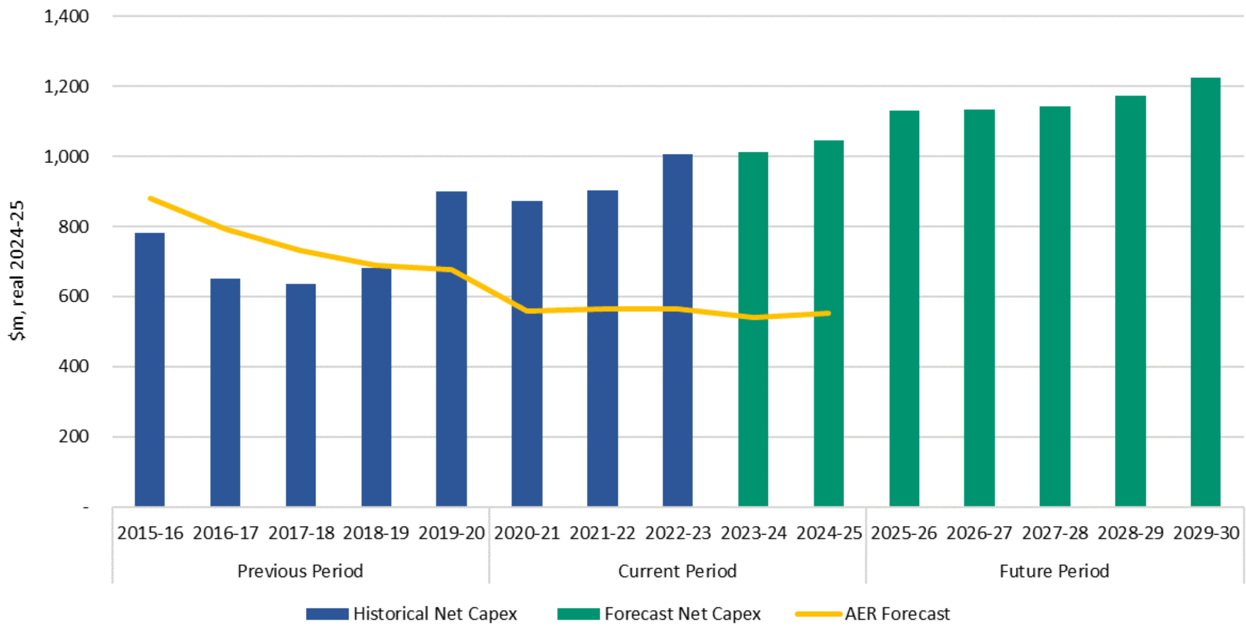
Our capital investments are categorised as set out in Figure 23.

Figure 23: Capex categories



For the 2025-30 regulatory control period we are forecasting capex of $5,805 million, an increase of 20 per cent from our current regulatory control period (refer to Figure 24). We consider this level of capex is required to carry out the activities outlined in Figure 23 to achieve the capex objectives listed in clause 6.5.7 of the NER. For additional information see Attachment 5.1.01.

Figure 24: Capex between 2015 to 2030 ($m, real 2024-25)



The data supporting Figure 24 is provided in Table 22 and Table 23.

Table 22: Historical capex ($m, real 2024-25)

	Previous Period					Current Period		
$m, real 2024-25	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
AER forecast[1]	880.1	793.5	730.4	689.6	677.6	558.6	563.6	564.9
Total net capex[1]	781.9	652.4	634.9	682.8	900.8	872.0	901.6	1,005.6

Note 1: Excludes disposals.

Table 23: Forecast capex ($m, real 2024-25)

	Current Period		Future Period				
$m, real 2024-25	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
AER capex forecast[1]	541.8	551.7	n/a	n/a	n/a	n/a	n/a
Total net capex[2]	1,011.6	1,046.7	1130.8	1,132.7	1,143.9	1,172.9	1,225.1

Note 1: Excludes disposals

Key drivers of our capex for 2025-30 include:

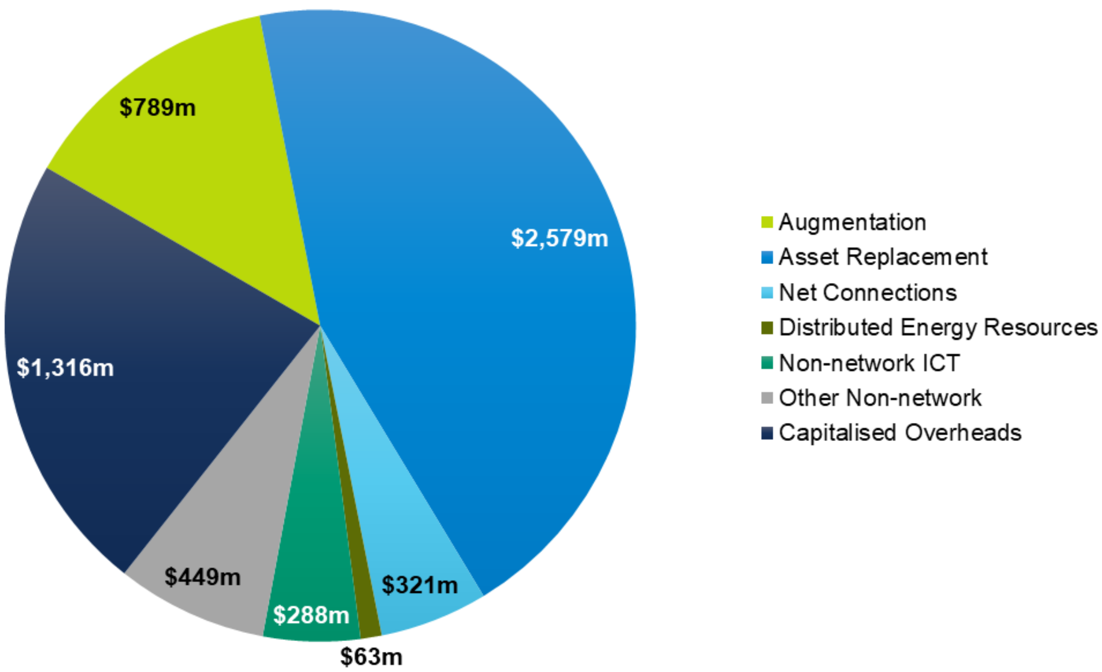
- strong population growth driving increased demand, with a forecast rise of 1 per cent annually in system peak demand
- security, performance, and reliability needs of customers
- the requirement to maintain assets to ensure they are operating safely and efficiently over their lifetimes
- annual average growth in new customer connections of around 1.6 per cent, in line with expected population growth in Queensland
- the increasing penetration of rooftop solar, which will cause minimum demand to fall by an average of 100MW annually
- the transition to an intelligent grid capable of meeting future customer needs, and
- ICT, property, fleet and equipment costs to support our growing network program.

Approximately $2,579 million (44 per cent) of our forecast capex program is to maintain the safety and reliability of our ageing network, $789 million (14 per cent) is to reinforce areas of the network experiencing growth, reliability or power quality issues, $63 million (1 per cent) is to integrate DER into the network and $321 million (6 per cent) is for connecting new customers or upgrading existing connections (after taking into account capital contributions from customers).

We propose to invest around $288 million (5 per cent) of total capex into non-network ICT to support our cyber security, modernise our customer experience and improve staff efficiency. We also forecast that we will spend around $449 million (8 per cent) of our capex on property, fleet, and tools and equipment, including investments to catch-up on replacing ageing vehicles that were unable to be replaced due to market supply challenges in the current regulatory control period.

Our capitalised overheads are expected to be around $1,316 million (23 per cent) of total capex, reflecting the forecast increase in our overall capex requirements and increased resourcing required to deliver our forward investment programs. Refer to Figure 25 for a break-down in forecast capital spend for the 2025-30 regulatory control period.

Figure 25: Capex for 2025 to 2030 by category ($m, real 2024-25)



5.1.1 Supporting documentation

The following document supports this section:

Document Name	Reference	File name
Addressing Capex objectives, criteria and factors	5.1.01	Ergon - 5.1.01 – Addressing Capex objectives, criteria and factors – January 2024 - public

5.2 Key assumptions

Table 24 details the key assumptions underpinning our capex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6.1.2(6) of the NER, as discussed in section 12.8.1 of this Regulatory Proposal. A copy of the certification is provided in Attachment 12.04.

Table 24: Key assumptions – Capex

	Issue	Assumption
1	Structure and ownership	Our forecasts are based on our current company structure and ownership arrangements.
2	Legislative and regulatory obligations	Our forecasts are based on our current legislative and regulatory obligations and our Distribution Authority.
3	Service classification	We will apply the service classification in the AER's Final F&A.
4	Customer preferences and expectations	The preferences and expectations of our customers and stakeholders revealed through our stakeholder engagement program have been considered in developing our Regulatory Proposal.
5	Service outcomes	We will maintain, but not improve, our average system-wide service outcomes, consistent with clauses 6.5.6(a) and 6.5.7(a) of the NER.
6	Forecast capex and opex	Our capex and opex forecasts have been developed to enable the requirement to deliver safety, reliability and customer outcomes.
7	Demand	Our base case network peak demand forecast provides an appropriate basis for our network augmentation forecast.
8	Customer numbers	Our base case customer number forecast provides an appropriate approach for our connections capex forecast and the customer numbers component of our opex rate of change.
9	Cost allocation	Our cost allocation methodology (CAM) provides an appropriate basis for attributing and allocating costs to, and between, our distribution services.
10	Unit rates/standard estimates	Unit rates/standard estimates are used in the development of our bottom-up forecasts where appropriate.
11	Real cost escalations for capex	Our real cost escalations used for our capex forecasts are reasonable and reflect prudent and efficient costs.
12	Inflation	Our forecast inflation is reasonable and reflects the inflation-related costs that we will incur.

5.2.1 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
SCS Capex model	5.2.01	Ergon - 5.2.01 – Model SCS Capex - January 2024 – public
Expenditure forecasting methodology	5.2.02	Ergon - 5.2.02 - Expenditure forecasting methodology – June 2023 - public
Distribution Annual Planning Report	5.2.03	Ergon - 5.2.03 - Distribution Annual Planning Report - December 2023 - public
Strategic Asset Management Plan	5.2.04	Ergon - 5.2.04 - Strategic Asset Management Plan - January 2024 - public
Cost Benefit Framework and Principles	5.2.05	Ergon - 5.2.05 - Cost Benefit Framework and Principles - January 2024 - public
Network Risk Framework	5.2.06	Ergon - 5.2.06 - Network Risk Framework - January 2024 – public
Network Deliverability Strategy	5.2.07	Ergon - 5.2.07 - Network Deliverability Strategy - January 2024 – public
Cost Comparison of Ergon RIN Unit Costs to the NEM	5.2.08	Ergon - 5.2.08 - Cost Comparison of Ergon RIN Unit Costs to the NEM - January 2024 - public
Demand Management Plan 2023-2024	5.2.09	Ergon - 5.2.09 - Demand Management Plan 2023-2024 - January 2024 - public
Capitalisation Policy	5.2.10	Ergon – 5.2.10 – Capitalisation Policy – January 2024 - public

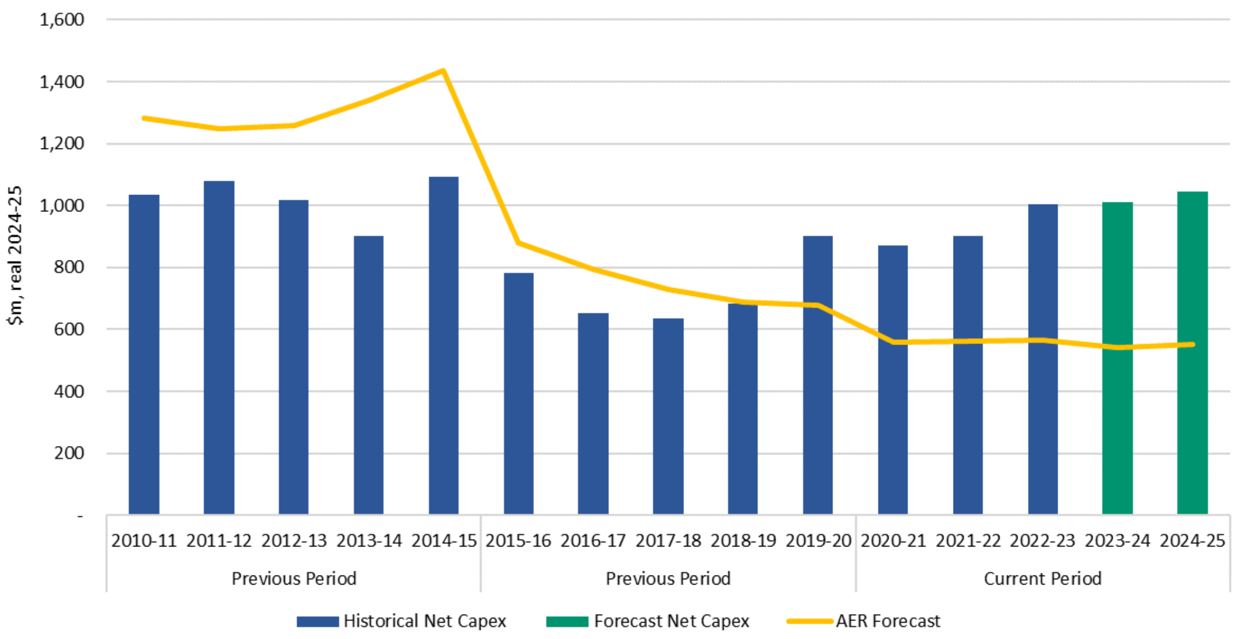
5.3 Historical capital expenditure

As part of our distribution determinations, the AER must decide if the total forecast capex that we put forward reasonably reflects prudent and efficient costs and a realistic expectation of future demand cost inputs.[8] As part of this process, we put forward, and the AER assesses, forecasts for each category of our capex requirement. We manage our overall capital spend across the different categories of capex with a view to not materially exceed the total AER capex forecast for the regulatory control period.

We have worked hard to reduce our capex to provide bill relief to customers. From 2010-11 to 2018-19 we consistently spent below the AER annual capex forecast (refer to Figure 26). This underspend was partially in response to a relaxation of the network security standards following the 2011 Electricity Network Capital Program Review. As a result of these changes we returned $99.2 million to customers through lower network prices during the 2010-15 regulatory control period. Lower expenditure than the AER's repex forecast also contributed to the underspend during this period. The total underspend over the nine years between 2010-11 and 2018-19 is 18 per cent.

[8] Clause 6.5.7(c) of the NER.

Figure 26: Capex between 2010 and 2025 ($m, real 2024-25)



The data supporting Figure 26 is provided in Table 25 and Table 26.

Table 25: Capex against AER forecast between 2010 and 2020 ($m, real 2024-25)

	Previous Period					Previous Period				
$m, real 2024-25	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
AER forecast[1]	1,283.7	1,248.0	1,259.8	1,340.5	1,435.3	880.1	793.5	730.4	689.6	677.6
Net capex[2]	1,036.2	1,077.7	1,018.7	901.9	1,092.6	781.9	652.4	634.9	682.8	900.8
Difference[3]	247.5	170.3	241.1	438.6	342.7	98.2	141.1	95.6	6.8	-223.2

Notes:
1. Excludes disposals.
2. Excludes disposals. Actuals for 2015-16 to 2019-20.
3. Positive value indicates we spent less than the AER capex forecast. Negative value indicates an overspend against forecast.

Table 26: Capex against AER forecast between 2020 and 2025 ($m, real 2024-25)

	Current Period				
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**
AER forecast[1]	558.6	563.6	564.9	541.8	551.7
Net capex[2]	872.0	901.6	1,005.6	1,011.6	1,046.7
Difference[3]	-313.4	-338.0	-440.7	-469.8	-495.0

Notes:
1. Excludes disposals.
2. Excludes disposals. Actuals for 2020-21 to 2022-23 and estimated for 2023-24 and 2024-25.
3. Positive value indicates we spent less than the AER capex forecast. Negative value indicates an overspend against forecast.

5.3.1 Current regulatory control period

Our capex increased during the current regulatory control period, primarily driven by our investment across regional Queensland in refurbishment and replacement works to address the performance challenges of an ageing network and meet community safety and reliability expectations. These works included targeted pole and conductor replacements in older sections of the network. In addition, we invested heavily in a major non-network ICT portfolio of works that involved transforming and consolidating core systems and business processes which has allowed us to work more efficiently and with a higher level of cyber security.

We estimate that for the current regulatory control period we will have spent around $4,838 million in capital, which is 74 per cent ($2,057 million) higher than the forecast approved by AER for the 2020-25 regulatory control period. Our financial performance for the 2020-25 regulatory control period is discussed in Chapter 1.

5.3.2 Ex post period

Clause 6.12.2(b) of the NER requires the AER to include in any draft or final distribution determination, a statement on the extent to which the roll forward of the RAB meets the capex incentive objective. This statement will be for the regulatory control period just ending. Where a DNSP has spent more than the AER's forecast capex, the AER may exclude capex above its forecast from the RAB if it does not reasonably reflect the capex criteria.

The relevant period over which the AER will make its assessment is the first three years of the current regulatory control period and the last two years of the preceding regulatory control period.[9] For Ergon Energy Network's Regulatory Proposal for the 2025-30 regulatory control period the ex post period is 2018-19 to 2022-23. For the ex post period our actual capex is 43 per cent higher than the AER's forecast capex, driven predominantly by a higher than forecast spend in repex and non-network ICT. Table 27 is a summary of the actual expenditure over the review period compared to the AER's forecast.

Table 27: Actual capex compared to AER forecast for ex post period

$m, real 2024-25	AER Forecast 2018-19 to 2022-23	Actual Capex 2018-19 to 2022-23	Variance from Forecast[1]	
Augex	400.2	269.2	130.9	33%
Customer connections capex (net)	270.7	314.9	-44.2	-16%
Repex	989.6	2,180.6	-1,191.1	- 20%
Non-network capex				
ICT	*132.7*	*246.3*	*-113.5*	*-86%*
Property	*99.8*	*151.5*	*-51.7*	*-52%*
Fleet	*185.6*	*129.1*	*56.5*	*30%*
Plant & Equipment	*33.6*	*34.7*	*-1.1*	*-3%*
Capitalised overheads	942.1	1,036.5	-94.4	-10%
Total Net Capex[2]	**3,054.2**	**4,362.7**	**-1,308.5**	**-43%**

Notes
1. Positive value indicates we spent less than the forecast. Negative value indicates an overspend against forecast.
2. Net capex in this table does not account for asset disposals.

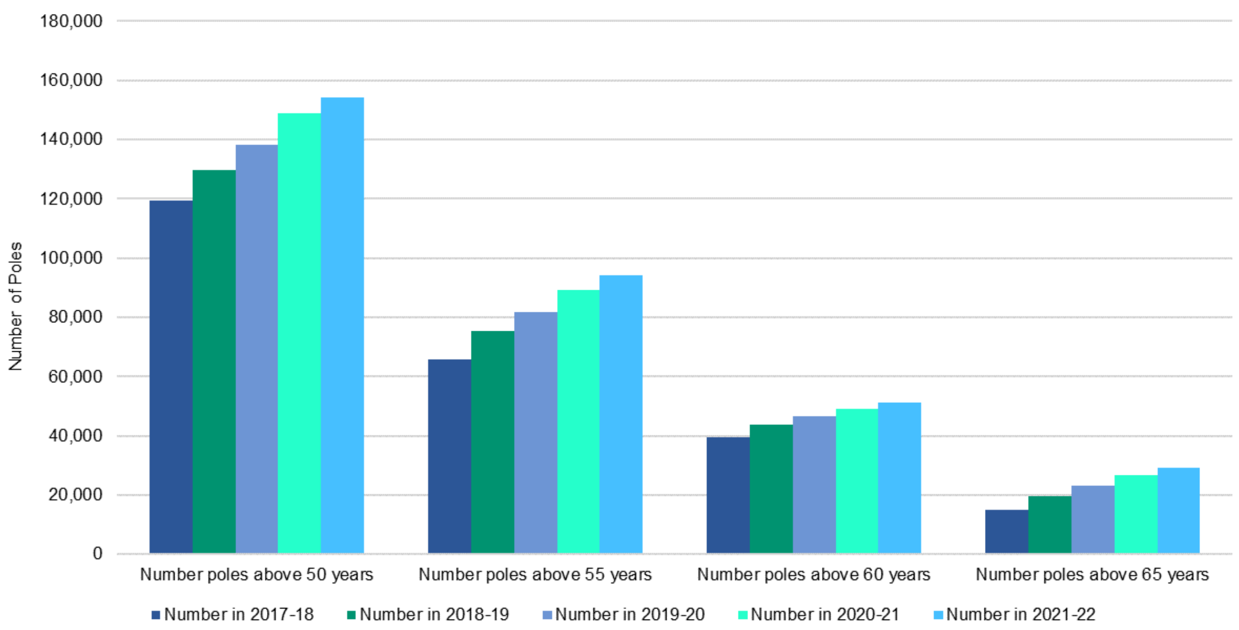
[9] AER, 2023, *Capital expenditure incentive guideline for electricity network service providers version 2,* April 2023, p.12.

5.3.2.1 Replacement capital expenditure

A high proportion of our network was established over 50 years ago and assets are nearing the end of their useful life. As a prudent operator, we have worked to optimise the life of these assets to ensure best value for our customers through condition-based asset replacement. However, over the last five years the need for asset replacement has risen due to an increasing asset failure rate, most critically our pole failure rates. As a responsible distribution entity, we have an obligation to increase our investment in asset replacement to maintain a safe and reliable network.

The ageing profile of our assets is demonstrated by the chart in Figure 27 below. Despite the increase in our pole replacements, the number of poles above 50 years old are still increasing year-on-year.

Figure 27: Increasing Age of Poles (2017-18 to 2021-22)



The expenditure incurred over the last five years to maintain the safety of our communities and reliability of our infrastructure is greater than the repex forecasted by the AER. We consider that this expenditure was prudent, efficient and necessary for us to meet our obligation to operate a safe and reliable network. These investments will benefit customers in the long-term by improving reliability and safety outcomes through reducing unassisted failures and providing environmental benefits through the avoidance of possible bushfires caused by asset failures. More details can be found in our ex post review of capex attachments included with our submission (Attachments 5.3.01 to 5.3.17).

5.3.2.2 Non-network ICT

In the 2015-20 regulatory control period, we had a significant interdependent legacy application portfolio that was overdue for replacement. Addressing legacy application issues evolved into a major multi-year, complex business transformation, which became known as the 'DEBBs portfolio'. The scope, approach, and governance of the DEBBs portfolio materially evolved over time. Ultimately the DEBBs portfolio encompassed 48 separate projects with a strong focus on addressing significant business change activities.

This complex portfolio of activities was the key driver of our high capital spend on non-network ICT during the ex post review period. A further driver was our unplanned investment in cyber security stemming from new compliance obligations, and a heightened risk of cyber-attacks across Australia targeting critical infrastructure providers.

It should be noted that, as discussed in our Draft Plan, Ergon Energy Network does not intend to seek to recover the expenditure on ICT capex above the amount that was included in the forecasts by the AER for the ex post review period. Further information on the drivers of the non-network ICT capex during the ex post period, and the lessons learned from this experience, are provided in Attachment 5.3.11.

5.3.2.3 Capitalised overheads

The higher than forecast program of work over the ex post review period led to an increase in the costs of activities required to support the program (capitalised overheads). The support costs include activities such as network planning and project governance.

5.3.2.4 Property

The non-network property forecast can vary significantly year-to-year, as it is often dependent on a small number of major projects. This means that any delay (or early start) to a proposed major project can impact the performance against the AER forecast each year. The AER forecast for the 2015-20 period was heavily weighted towards the start of the period. Of the $214 million ($2024-25) AER estimate for 2015-20, 65 per cent was included in the first two years (2015-16 and 2016-17).

Due to a delay in spend at the start of the 2015-20 regulatory control period, actual expenditure was shifted into the ex post period. There was a corresponding underspend in 2015-16 and 2016-17.

Further information on the drivers of the non-network property capex during the ex post period can be found in Attachment 5.3.01.

5.3.2.5 Connections

Our net connex was below the AER forecast for the first two years of the ex post period (2018-19 and 2019-20). However, we spent more than the AER forecast for net connex during the remaining three years of the review period (2020-21 to 2022-23). We attribute this to two main factors:

- our 2020-25 investment proposals were completed during 2018-19 on the back of a construction boom, and at that time, a slowdown in construction was anticipated for the 2020-25 period. Therefore, the forecast for connex for 2020-25 was lower than the forecast for the 2015-20 period, and
- the unanticipated impact of Covid-19 on migration in regional Queensland and the associated increase in new connections from 2020-21 resulted in an increase to connex.

Further information on the connections capex during the ex post period can be found in Attachment 5.3.01.

5.3.3 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
Capex ex post justification - Overview	5.3.01	Ergon - 5.3.01 - Capex ex post justification – Overview - January 2024 - public
Capex ex post justification - Pole Repex	5.3.02	Ergon - 5.3.02 - Capex ex post justification - Pole Repex - January 2024 - public
Capex ex post justification - Conductor Repex	5.3.03	Ergon - 5.3.03 - Capex ex post justification - Conductor Repex - January 2024 - public
Capex ex post justification - Pole Top Structure Repex	5.3.04	Ergon - 5.3.04 - Capex ex post justification - Pole Top Structure Repex - January 2024 - public
Capex ex post justification - Switchgear Repex	5.3.05	Ergon - 5.3.05 - Capex ex post justification - Switchgear Repex - January 2024 - public
Capex ex post justification - Transformer Repex	5.3.06	Ergon - 5.3.06 - Capex ex post justification - Transformer Repex - January 2024 - public
Capex ex post justification - Underground Cable Repex	5.3.07	Ergon - 5.3.07 - Capex ex post justification - Underground Cable Repex - January 2024 - public
Capex ex post justification - Services Repex	5.3.08	Ergon - 5.3.08 - Capex ex post justification - Services Repex - January 2024 - public
Capex ex post justification - SCADA, Network Control and Protection Repex	5.3.09	Ergon - 5.3.09 - Capex ex post justification - SCADA, Network Control and Protection Repex - January 2024 - public
Capex ex post justification - Other Repex	5.3.10	Ergon - 5.3.10 - Capex ex post justification - Other Repex - January 2024 - public
Capex ex post justification - Non-network ICT	5.3.11	Ergon - 5.3.11 - Capex ex post justification - Non-network ICT - January 2024 - public
PIR - Pole replacements	5.3.12	Ergon - 5.3.12 - PIR - Pole replacements - January 2024 - public
PIR - Conductor replacements	5.3.13	Ergon - 5.3.13 - PIR - Conductor replacementsJanuary 2024 - public
PIR - Cross-arm replacements	5.3.14	Ergon - 5.3.14 - PIR - Cross-arm replacements - January 2024 - public
PIR – Switches replacements	5.3.15	Ergon - 5.3.15 - PIR - Switches replacements - January 2024 - public
PIR - Distribution transformer replacements	5.3.16	Ergon - 5.3.16 - PIR - Distribution transformer replacements - January 2024 - public
PIR - Service line replacements	5.3.17	Ergon - 5.3.17 - PIR - Service line replacements - January 2024 - public

5.4 Replacement expenditure

We replace and refurbish existing assets that are ageing or in poor condition to meet our reliability and safety obligations and the expectations of our communities. Our proposed repex for the 2025-30 regulatory control period is $2,579 million. This is in line with our long-term historic average for replacement and represents a continuation of our existing asset management practices (refer to Figure 28).

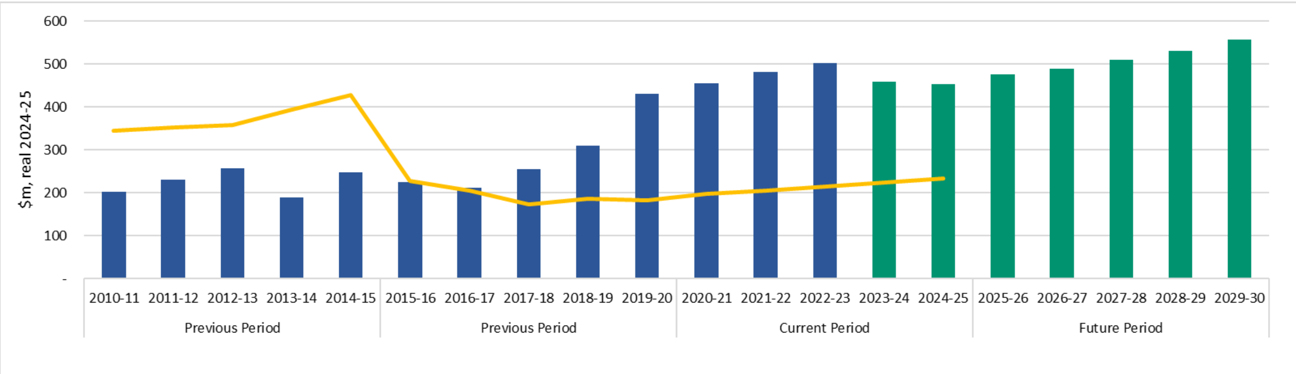
Customers benefit from this investment through improved reliability. Where an asset fails while in-service, there is an immediate impact on customers through an electricity outage. Our focus is to maintain our current level of reliability because our customers have told us that the existing balance between cost and reliability is about right and that they are provided with a reliable electricity supply.[10]

We propose to replace assets prior to in-service failures or defects where it is cost-effective to do so. This improves reliability for customers and, for our sub-transmission assets, it is more efficient as emergency replacements following a failure are higher cost.

We are also focused on safety considerations, as the risk of injury or fatalities to the community and our staff are higher for different types of network assets. For example, our distribution assets are typically in public areas, unlike our substation assets which are installed inside a fenced, secure site. Consequently, it is often preferred to replace or refurbish an asset prior to failure where there is a strong safety benefit to the community.

Some assets are replaced on failure or upon detection of a defect. In accordance with our asset inspection programs we inspect and categorise defects based on risk and then determine an efficient delivery program to minimise customer outages during rectification.

Figure 28: Replacement capex between 2010 to 2030 ($m, real 2024-25)



The data supporting Figure 28 is provided in Table 28 and Table 29.

Table 28: Repex between 2010 to 2020 ($m, real 2024-25)

	Previous Period					Previous Period				
$m, real 2024-25	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
AER forecast	345.4	352.2	358.1	393.7	428.2	227.2	205.8	173.9	187.0	182.6
Repex	202.5	230.8	257.6	189.4	247.9	226.1	212.8	255.2	310.4	430.6

[10] The 2023 Queensland Household Energy Survey was completed by 1,816 Ergon Energy Network customers with 76 per cent of participants responding that they believe that the existing balance between cost and reliability is about right and 70 per cent believe that they are provided with a reliable electricity supply.

Table 29: Repex between 2020 to 2030 ($m, real 2024-25)

	Current Period					Future Period				
$m, real 2024-25	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
AER forecast	198.6	206.4	215.0	224.1	234.1	n/a	n/a	n/a	n/a	n/a
Repex[1]	455.9	481.9	501.8	458.4	453.6	479.3	491.8	512.7	534.3	560.9

Note 1. Estimated for 2023-24 to 2029-30.

5.4.1 Our replacement history

As Figure 28 demonstrates, Ergon Energy Network's level of replacement in the period from 2010 to 2017 was low compared to more recent years. With a large volume of network being constructed in the 1970s and 1980s, a substantial number of our assets are reaching the end of their serviceable lives in the current and next regulatory control periods. We took prudent actions to extend the lives of these assets between 2010 and 2017 but are now unable to continue to avoid replacing these assets due to safety risks and reliability impacts. Further deferral of asset replacements would not have been consistent with the National Electricity Objective of investing in the long-term interest of customers.

As an example, the volume of pole replacements during this period (2010-17) was around 3,600 poles per year. We have around one million poles in our network, which would infer an asset life for a single pole of 230 years. Because a significant portion of our assets were established in the 1970s and 1980s, we were able to maintain this low level through the 2010-2017 period. However, these assets are now approaching 60 years of age, and our replacement rates need to increase. Figure 27 in section 5.3.2.1 shows that despite the expenditure we have undertaken between 2018 and 2023, our pole population has continued to increase in age over this time. This is a similar story for our other major asset categories, such as pole-top structures, conductor, service lines and transformers.

5.4.2 Our forecasting approach

Our forecast repex for the 2025-30 regulatory control period is mainly driven by the asset management objectives outlined in our Strategic Asset Management Plan (Attachment 5.2.04), our safety, environmental and regulatory obligations and the application of our Cost Benefit Framework and Principles (Attachment 5.2.05). These ensure that we produce forecast expenditure that is prudent and efficient and matches customer needs and preferences through our benefits streams that we quantify in our cost-benefit analysis.

Our repex programs fall into two categories:

- **Condition and risk** - where we propose to replace assets prior to in-service failures or defects, we utilise the condition of our assets and other tools to determine the probability of failure. We then assess the consequences of failure by applying our Cost Benefit Framework and Principles. By quantifying and monetising the risk of failure through our five value streams (i.e. reliability, export, safety, environmental and financial), we determine the customer and community benefits of proactive replacement to ensure that our expenditure is proportionate to the level of risk, and

- **Reactive** - reactive replacements are either undertaken following an in-service failure, or where we have identified a defect in an asset. To forecast this type of expenditure, we utilise historical failure and defect rates and the condition of our assets to assess the likelihood of defects and failures. Reactive replacement programs are predominately driven by well-established inspection programs, which are used to identify and replace assets at imminent risk of in-service failure and to manage asset condition where proactive replacement is not economical.

Our proposed repex represents a balance of condition and risk, and reactive programs to provide a prudent means of achieving the asset management objectives.

5.4.2.1 AER repex model comparison

In its *Expenditure Forecast Assessment Guideline for Electricity Distribution*, the AER outlines its use of the repex model to help determine the efficient costs of asset replacement over a forthcoming regulatory control period. The model provides a top-down view of expenditure by comparing DNSP replacement rates and costs. The AER uses this model as a threshold test to identify areas of potential difference from DNSP forecasts to inform areas for additional review. We also use the AER repex model as a tool for a top-down challenge and check of repex forecast requirements, mainly at an overall repex level rather than at an asset category group level.

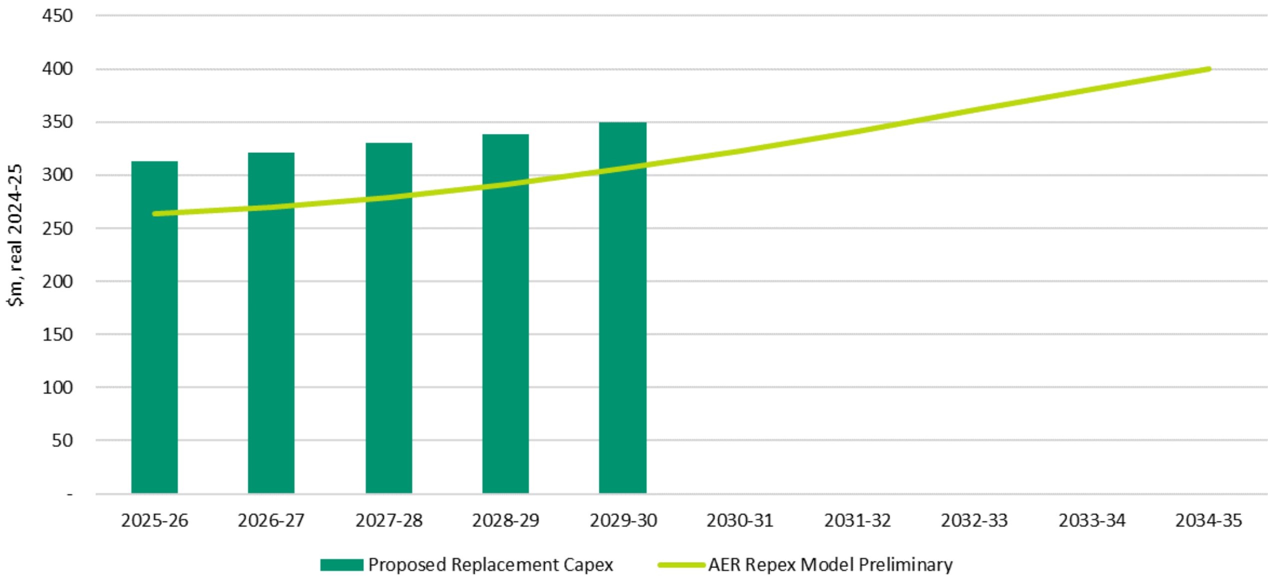
To determine the level of replacement we expect to undertake during a regulatory control period, we assess the probability and consequence of an asset failure. The probability of a failure is influenced by the age of the asset and the asset's condition, which also influences the optimum timing of the project or program. Factors such as safety, environment, changes in defect rates and obsolescence issues are also considered.

The AER assesses repex based on two broad categories of assets:

- **Assets that are capable of being modelled based on the repex model** - This category includes six asset classes (i.e. poles, overhead conductor, underground cables, switchgear, transformers, and services). Often referred to as modelled repex, these six categories comprise 64 per cent of our total repex, and
- **Assets that are not well suited to the AER repex model** – This category comprises all remaining asset classes (i.e. network communication, control and protection system assets, pole-top structure assets, and other miscellaneous items such as battery systems, fire systems, and fences).

We have engaged with the AER to understand their application of repex modelling, so that we can consider the same scenarios and utilise the repex modelling in a similar manner. Figure 29 compares our optimised repex forecast for modelled assets (based on the six asset categories outlined above) with repex modelling outputs.

Figure 29: Comparison of modelled repex to AER repex model output



Our proposed expenditure is higher than the AER repex model by 17 per cent. This is most evident in the switches and transformer asset classes. While we consider the outputs of the AER's repex model as instructive, the challenges of our ageing network and under-investment in the 2015-20 regulatory control period, and our need to catch up on the replacement of our assets means that the repex model is not the appropriate predictive tool to forecast our future expenditure requirements.

We have undertaken a cost-benefit analysis in all our asset categories to ensure the prudency of our proposed replacement program and have utilised the AER's RIN data to compare our costs with other DNSPs in the NEM. In this context, we believe that our overall repex program is prudent and efficient.

5.4.3 Summary of proposed investments

Our proposed investments in repex involve three broad areas of expenditure. Our sub-transmission repex typically involves proactive replacement of assets in our zone and bulk supply substations and sub-transmission feeders. Our distribution expenditure relates to the replacement of our poles and wires assets at lower voltages, and are typically lower value, high volume replacement programs. Other enabling repex is the replacement of assets to perform our critical grid communications, protection and other system enabling functions. Our repex by category is provided in Table 30.

Table 30: Repex by category for 2025 to 2030 ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Sub-transmission	67.0	69.5	73.2	72.5	80.5	**362.7**
Distribution	357.5	362.6	368.6	371.9	378.9	**1,839.5**
Other	54.8	59.8	70.9	89.8	101.5	**376.9**
Total[1]	**479.3**	**491.8**	**512.7**	**534.3**	**560.9**	**476.1**

Note 1: Totals may not add due to rounding.

5.4.3.1 Sub-transmission replacement expenditure – condition and risk

Ergon Energy Network uses the Condition Based Risk Management (CBRM) methodology to identify individual sub-transmission assets nearing the end of their lifecycle. These investments are all undertaken following a site-specific assessment of asset condition, consideration of the type and size of load supplied by the network, and safety and environmental risk exposure to the community and our staff. The scope and timing of replacement or refurbishment (i.e. life extension) is informed by the probability of failure and the assessed consequence of the failure. Typical consequences we would expect from not undertaking a proactive replacement for sub-transmission include:

- **Reliability** - unserved energy to our customers following an in-service failure of an item of plant. This generally forms a large part of the customer benefit from our sub-transmission repex
- **Safety** - risk of injury or fatalities to the community and our staff associated with a catastrophic failure of equipment
- **Environmental** - examples include damage from a transformer or other equipment, oil leaks and fires resulting from catastrophic failures, and
- **Financial** - higher replacement cost for undertaking an emergency replacement following a failure. This also forms a large part of the customer benefit from our sub-transmission repex, as replacing equipment following a failure generally costs more given the need to restore our network to a normal state to cater for any subsequent failures.

In addition to our cost-benefit analysis to identify the need for a proactive replacement, we consider the required network security standards and obligations, such as the Safety Net obligations outlined in our Distribution Authority. We also consider alignment with other network drivers, such as augex and connex, to ensure the final option is the most cost-effective and provides a holistic solution in the long-term interests of our customers.

Non-network alternatives, such as demand management through load reductions, are always considered in our sub-transmission planning and, where applicable, non-network alternative options for replacement are investigated through the Regulatory Investment Test for Distribution (RIT-D) process.

Estimated costs for these projects are site-specific. Scope-based estimates are undertaken through our estimation system (Ellipse). These estimates are also compared to actual costs of similar projects to ensure the estimate is reflective of the likely cost.

The highest proportion of expenditure in this category is driven by major substation asset replacement, with the majority of this being 33/11kV transformers and 33kV circuit breakers.

5.4.3.2 Distribution replacement expenditure – condition and risk

We have developed the condition and risk distribution replacement programs based on our analysis of asset performance and quantification of risk. The major component of this capex is in the distribution line refurbishment programs, which include replacement of overhead conductor, pole top structures and service lines that are approaching end-of-life. Assets that are identified as approaching end-of-life are prioritised according to risk and are bundled into logical packages of work to facilitate efficient delivery. Volumes of replacement works are determined based on the overall risk exposure and the performance of our asset classes, such as trends in defect and failure rates. This ensures programs are efficient and continue to meet asset management objectives, particularly community and staff safety, and legislative obligations.

Many of our distribution repex programs include what we term as 'consequential' replacements. That is, where it is efficient to do so we will replace adjacent assets as part of this program. For example, when replacing a conductor we may also need to replace a pole or pole-top structure to enable the conductor to be replaced.

Three of our major distribution repex programs are:

- **Pole-top structures –** this program has been developed through determining a probability of failure through historic failure data and mathematical modelling techniques. This has been calibrated to accurately predict our past failures so we can be confident that our modelling will accurately predict future failures. Our Pole-top Structure Replacements Business Case (Attachment 5.4.02) outlines the cost-benefit approach of this program, and the options we have considered in addressing the need. This program also replaces service lines and distribution transformers as consequential replacements where appropriate
- **Overhead conductor replacement** – development of this program begins with an analysis of the condition and health of the asset population in accordance with the CBRM methodology. This process identifies individual assets nearing the end of their lifecycle. The risks and subsequent benefits of replacement are then quantified to ensure the expenditure to replace overhead conductor and the associated equipment needed to enact this program is proportionate to the risk. Our Overhead Conductor Replacements Business Case (Attachment 5.4.03) outlines the cost-benefit approach to this program, and the options we have considered in assessing the need.

  In the 2025-30 regulatory control period, we are proposing an increase in the volume of conductor that we replace. The condition of our overhead conductor assets continues to deteriorate over time, and we have a significant population of older style, thin-strand copper conductor that is at an increased risk of in-service failure. We have commenced replacement of some higher risk work throughout the current 2020-25 regulatory control period. However, a step up to the current replacement rate is required to ensure no deterioration in our network reliability and safety performance, and
- **Service lines** – as with pole-top structures, this program has been developed using historic failure and defect data to develop a probability of failure for our current population. Our Service Line Replacements Business Case (Attachment 5.4.05) outlines the cost-benefit approach of this program, and the options we have considered in addressing the need.

The benefits we typically expect to see from programs of this type include:

- **Reliability** - an unplanned outage on our network following an in-service distribution asset failure typically results in unserved energy to our customers. Minimising unserved energy forms a large part of the customer benefit from our distribution repex. It should be noted that these programs are targeted at maintaining our existing network reliability and ensure that we do not experience an increase in unplanned outages from asset failures as the condition of our assets deteriorates over time
- **Safety** – risk of injury or fatalities to the community and our staff associated with a catastrophic failure of equipment. Unlike our substation assets which are installed inside a fenced, secure site, most of our distribution assets are in publicly accessible areas. As such, proactively replacing assets in poor condition reduces the likelihood of these types of failures resulting in safety incidents in the community
- **Environmental** – fire starts following in-service failure of electrical equipment can cause bushfires. Proactively replacing equipment will reduce the likelihood of these events being caused by our assets, and

- **Financial** – following an in-service failure of a distribution asset, we generally need to replace the equipment to restore supply. For distribution assets, we do not typically expect this to cost more than if we proactively replaced the item. However, our cost-benefit analysis factors include avoided replacement as a benefit on the basis that we will avoid this future cost.

5.4.3.3 Distribution replacement expenditure - reactive

Our reactive distribution repex falls into two categories:

- **Defect driven** – we have included forecast expenditure for the replacement or refurbishment of assets that are identified through our routine inspection and maintenance programs as being at end-of-life and at risk of imminent in-service failure . Volumes of replacements under these programs are forecast based on historic asset performance, available condition data, and an assessment of the probability of failure across our asset population. In identifying defects, our asset inspectors categorise defects based on the condition of the asset, which identifies a likely period the asset will be able to remain in service prior to failing. This allows us to prioritise our defects based on risk and bundle works into efficient delivery programs to minimise customer outages during rectification. The major drivers for capex in this category include replacement of timber poles, pole-mounted plant and overhead services that are identified in our five-year cycle of overhead line inspection, and
- **In-service failures** – we have included forecast expenditure in our Regulatory Proposal for the replacement of equipment that we expect to fail in-service during the 2025-30 regulatory control period. This component of our expenditure forecast includes a demand-based allocation to replace assets because of in-service failure. Volumes of asset replacement in this category are forecast based on historical requirements, trends and an assessment of the probability of failure across our asset population. The major driver for capex in this category includes replacement of distribution transformers, poles, pole-top structures and underground cable following an in-service failure.

In assessing the requirement for reactive expenditure, we consider the impact our condition and risk programs will have on our overall asset condition across the period. Our forecast expenditure for reactive replacements considers where we have programs that are likely to reduce defects or failures in our network. Similarly, where we have programs that are largely ‘replace on failure’, such as for distribution transformers, we assess the costs and benefits of a proactive program in these expenditure categories to ensure that the optimal program (proactive versus reactive) is chosen for these assets.

Estimated costs for these allocations are based on historical unit rates and expenditure in these categories and are compared to our bottom-up estimation systems to ensure confidence in the proposed expenditure.

5.4.3.4 Network control and grid communications

Network control and grid communications are a range of equipment required to ensure the efficient operation of our network, benefiting customers by providing a reliable, safe and efficient operation of the network. Technologies include microwave and fibre optic communications paths to allow for remote operation of our assets from our control room, relays that isolate the network when there are faults and other smart technologies that allow our network to operate at its optimum level. The development of the repex requirements for these assets is based on a combination of reactive, condition and risk-driven programs.

Reactive replacement programs are predominantly driven by in-service failures detected via continuous monitoring or inspection programs. These programs identify assets that have stopped operating, are no longer performing to specification, or are at imminent risk of failure. For some low-risk asset classes, such as distribution transformer monitoring units, certain intelligent electronic devices used in the Supervisory Control and Data Acquisition (SCADA) system and many telecommunications line driver and switch units, we use reactive replacement on a like-for-like replacement basis.

Condition and risk-based programs consider the condition, performance and risk of assets (including obsolescence or manufacturer's support) to identify assets approaching end-of-life. For the forthcoming regulatory control period, we are forecasting that more first-generation digital assets installed in the 1980s will approach their end-of-life. Planning assessments are undertaken to determine the most appropriate solution to meet network requirements, including non-network alternatives.

Like-for-like replacements are made for equipment such as:

- communications site infrastructure (i.e. generators, battery generators, batteries, chargers, equipment shelters and towers), providing protection, SCADA, and infield voice communications
- radio infrastructure providing field worker mobile communications capability for vehicle-to-vehicle and vehicle-to-depot, control room voice communications supporting maintenance and installation of power network infrastructure
- microwave link equipment that provides critical communications, including protection and SCADA, and
- communications infrastructure management and monitoring systems.

Due to the rapid pace of technology development, network solutions will often be based around modern equivalents. This includes replacing:

- analogue, electromechanical and first-generation digital protection relays with digital relays
- copper pilot wire (for protection communication) with fibre optic cables
- the Plesiochronous Digital Hierarchy for the transportation of digital data on our network with Multiprotocol Label Switching network equipment
- first-generation equipment that can only operate on copper pilot wire to provide critical communications capability where the consequence of failure is significant, such as loss of protection for faults on our primary assets, with equipment that operates via fibre optic cables, and
- switching, router and other substation communications equipment with latest generation equipment incorporating firewalling and other capabilities.

5.4.3.5 Cyber security network replacement expenditure

With the increased threat of cyber-attacks, replacement of our security operational technology assets is required to mitigate the risk of business disruptions associated with asset failures or through emerging cyber security vulnerabilities being exploited. This ensures the platform remains secure, reliable, and efficient, and that we meet our risk management obligations under the *Security of Critical Infrastructure Act* 2018 and align to our own cyber security risk appetite.

5.4.4 How this differs from our Draft Plan

Our overall repex is in line with the Draft Plan. Our replacement program formed one of our key investment priorities, and with the feedback on our investment priorities for our Draft Plan being positive, we have not changed our approach to repex in our Regulatory Proposal. We have updated some project and program timing and expenditure phasing, but there have been no changes to our major investment streams in repex.

5.4.5 Delivering for our customers

Our forecast repex has been developed in accordance with our Cost Benefit Framework and Principles, which has been developed around customer and community benefits. Through valuing reliability improvements and financial, safety and environmental risk reductions that result from our expenditure, we ensure that our investments provide long-term benefits to customers. With the major driver for repex being avoiding in-service failures, there are clear customer benefits from preventing network outages and providing a safe network for the community.

5.4.6 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
Business Case Pole Replacements	5.4.01	Ergon - 5.4.01 - Business Case Pole Replacements - January 2024 - public
Business Case Pole Top Structure Replacements	5.4.02	Ergon - 5.4.02 - Business Case Pole Top Structure Replacements - January 2024 - public
Business Case Overhead Conductor Replacements	5.4.03	Ergon - 5.4.03 - Business Case Overhead Conductor Replacements - January 2024 - public
Business Case Distribution Transformer Replacements	5.4.04	Ergon - 5.4.04 - Business Case Distribution Transformer Replacements - January 2024 - public
Business Case Service Lines Replacements	5.4.05	Ergon - 5.4.05 - Business Case Service Lines Replacements - January 2024 - public
Business Case Distribution Switches Replacements	5.4.06	Ergon - 5.4.06 - Business Case Distribution Switches Replacements - January 2024 - public
Business Case Circuit Breaker and Recloser Replacements	5.4.07	Ergon - 5.4.07 - Business Case Circuit Breaker and Recloser Replacements - January 2024 - public
Business Case Control System Replacements	5.4.08	Ergon - 5.4.08 - Business Case Control System Replacements - January 2024 - public
Business Case DC Supply Replacements	5.4.09	Ergon - 5.4.09 - Business Case DC Supply Replacements - January 2024 - public
Business Case Instrument Transformer Replacement	5.4.10	Ergon - 5.4.10 - Business Case Instrument Transformer Replacement - January 2024 - public
Business Case Protection Relay Replacements	5.4.11	Ergon - 5.4.11 - Business Case Protection Relay Replacements - January 2024 - public
Business Case Substation Transformer Replacements	5.4.12	Ergon - 5.4.12 - Business Case Substation Transformer Replacements - January 2024 - public
Business Case Underground Cable Replacements	5.4.13	Ergon - 5.4.13 - Business Case Underground Cable Replacements - January 2024 - public
Asset Management Plan Poles	5.4.14	Ergon - 5.4.14 - Asset Management Plan Poles - January 2024 - public

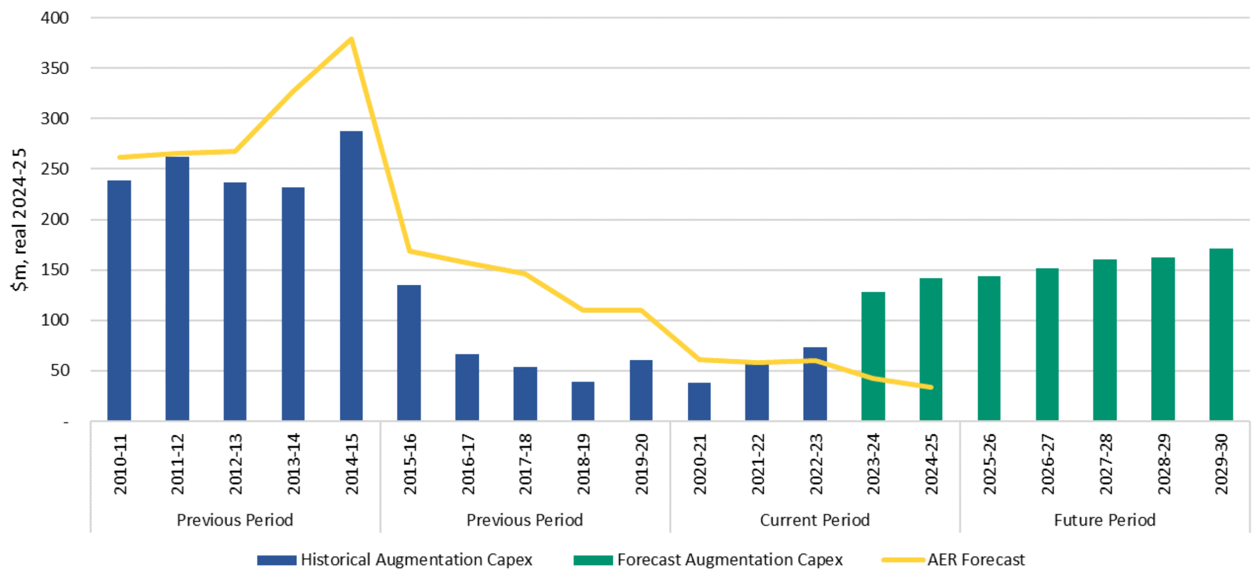
Document Name	Reference	File name
Asset Management Plan Pole Top Structures	5.4.15	Ergon - 5.4.15 - Asset Management Plan Pole Top Structures - January 2024 - public
Asset Management Plan Overhead Conductor	5.4.16	Ergon - 5.4.16 - Asset Management Plan Overhead Conductor - January 2024 - public
Asset Management Plan Transformers	5.4.17	Ergon - 5.4.17 - Asset Management Plan Transformers - January 2024 - public
Asset Management Plan Service Lines	5.4.18	Ergon - 5.4.18 - Asset Management Plan Service Lines - January 2024 - public
Asset Management Plan Switchgear	5.4.19	Ergon - 5.4.19 - Asset Management Plan Switchgear - January 2024 - public
Asset Management Plan DC Systems	5.4.20	Ergon - 5.4.20 - Asset Management Plan DC Systems - January 2024 - public
Asset Management Plan Control Systems	5.4.21	Ergon - 5.4.21 - Asset Management Plan Control Systems - January 2024 - public
Asset Management Plan Instrument Transformers	5.4.22	Ergon - 5.4.22 - Asset Management Plan Instrument Transformers - January 2024 - public
Asset Management Plan Protection Relays	5.4.23	Ergon - 5.4.23 - Asset Management Plan Protection Relays - January 2024 - public
Asset Management Plan Underground Cables	5.4.24	Ergon - 5.4.24 - Asset Management Plan Underground Cables - January 2024 - public
Asset Management Plan Circuit Breakers and Reclosers	5.4.25	Ergon - 5.4.25 - Asset Management Plan Circuit Breakers and Reclosers - January 2024 - public
Asset Management Plan Distribution Transformers	5.4.26	Ergon - 5.4.26 - Asset Management Plan Distribution Transformers - January 2024 - public
Replacement capex modelling supporting information	5.4.27	Ergon - 5.4.27 - Replacement capex modelling supporting information - January 2024 - public

5.5 Augmentation

As regional Queensland continues to grow and develop there is an increasing demand for electricity. To account for this increased demand, we will invest in reinforcing those areas of the network that do not (or are forecast to not) have sufficient capacity to meet customer demand. Without increasing our capacity to support our growing communities, customers would likely experience security of supply, reliability or power quality issues into the future.

Our proposed augex is $789 million for 2025-30. While we acknowledge this is an increase on the current period, this level of expenditure is in line with our long-term historic average for augmentation (refer to Figure 30) and reflects the challenges of a geographically dispersed, ageing network in times of forecast demand growth.

Figure 30: Augex between 2010 to 2030 ($m real 2024-25)



The data supporting Figure 30 is provided in Table 31 and Table 32.

Table 31: Augex between 2010 to 2020 ($m, real 2024-25)

	Previous Period					Previous Period				
$m, real 2024-25	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
AER forecast	261.7	265.2	268.0	327.3	378.9	169.3	157.0	146.1	110.3	110.3
Augex	238.8	262.5	236.5	231.7	287.5	135.0	66.8	53.8	39.5	61.1

Table 32: Augex between 2020 to 2030 ($m, real 2024-25)

	Current Period					Future Period				
$m, real 2024-25	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
AER forecast	60.8	58.4	60.3	42.5	33.6	n/a	n/a	n/a	n/a	n/a
Augex	38.1	56.9	73.7	128.2	141.9	143.9	151.2	160.0	162.4	171.2

5.5.1 Our forecasting approach

We invest in augex to meet the growing electricity needs of our customers to ensure that households and businesses have a reliable and safe supply. Our investments are carefully considered and assessed to maximise the value to customers over the long-term. We have two key considerations in developing our augex:

- **Compliance** - where we have clear legislative and regulatory obligations to undertake improvements on our network, our investments focus on the lowest cost over the long-term to achieve the outcomes required under those obligations and to maximise value for customers. Examples of compliance obligations include maintaining clearance of our conductors to ground and structures, meeting the Safety Net security criteria, Minimum Service Standards (MSS) and worst performing feeder requirements under our Distribution Authority, and
- **Cost-benefit analysis** - in accordance with our Cost Benefit Framework and Principles, we undertake investment in the network to maximise the value to customers over the long-term. We assess the current and forecast future performance of the network and its enabling systems, analyse the value of improvements for customers, and compare this to the estimated costs of any improvement initiative. Our preferred option is based on the best net present value (NPV) for each investment. Typical investments under cost-benefit analysis include reinforcement of the network to reduce or eliminate network outages, or additional protection systems capability to improve network safety and reliability.

5.5.2 Summary of proposed investments

We invest in augex to:

- address key areas of community development, population, and demand growth
- maintain the statutory and standard requirements pertaining to our networks, and address the obligations outlined in our Distribution Authority pertaining to Safety Net security criteria, MSS and worst performing feeder requirements, and
- provide additional functionality to support an intelligent grid through a range of network control and monitoring initiatives.

There are seven main categories of augmentation. The associated expenditure for each category is outlined in Table 33 and discussed in the following sections.

Table 33: Augex by category between 2025 to 2030 ($m, real 2024-25)

	Future Period					
	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Sub-transmission Growth	25.2	32.0	37.4	44.1	43.9	**182.6**
Distribution Growth	37.4	36.7	42.6	47.5	51.2	**215.4**
Clearance Programs	37.2	35.7	36.1	34.5	37.6	**181.1**
Reliability	2.8	2.8	2.8	2.8	2.9	**14.0**
Resilience	16.7	20.5	11.0	3.2	6.2	**57.6**
Grid communications, protection and control	22.9	21.8	28.3	28.4	27.6	**128.9**
Cyber security	1.8	1.8	1.8	1.8	1.8	**9.0**
Total[1]	**143.9**	**151.2**	**160.0**	**162.4**	**171.2**	**788.6**

Note 1: Totals may not add due to rounding.

5.5.2.1 Sub-transmission growth

Our customers have benefited from the significant investments we made 10 to 15 years ago to support strong demand growth and stringent N-1 security criteria. The network capacity established during this period, combined with the change in security and reliability requirements prescribed by Safety Net obligations in our Distribution Authority, meant that we were able to rely on our existing sub-transmission capacity and limit our augex requirements in the 2015-20 and 2020-25 regulatory control periods. Our network utilisation increased during this period. This has meant that customers had reliable and secure electricity supply without the need for significant investment during the last 10 years.

However, with population growth forecast for key areas of our network, we are now at the point where our sub-transmission network requires investment to ensure that our customers continue to receive a reliable and secure supply.

To determine the optimal level of sub-transmission augex:

- for the growth components of our sub-transmission augex, we undertook an assessment of normal network condition demand forecasts, plant ratings and our reliability and security of supply obligations under the Safety Net (i.e. this expenditure is generally driven by compliance requirements)
- where there are identified network limitations, we considered a variety of feasible network and non-network solutions
- for all sub-transmission projects, we proactively seek demand management solutions to reduce peak demand and defer network investment, and
- all major investments are subject to a RIT-D and market test of alternative solutions.

The successful use of demand management has contributed to limiting our augex in the 2015-20 and 2020-25 regulatory control periods. We will continue to utilise this capability through the 2025-30 regulatory control period, as well as seek to expand our capability in areas of high growth to ensure that we limit augex to only what is required.

Major network investments for the 2025-30 regulatory control period include:

- **New feeder from Glenella to Planella –** the area around Planella in the Mackay region is continuing to grow and Planella substation is currently supplied by a single feeder. With a significant load supplied by this substation, we are forecasting the requirement to establish a new feeder to the region to ensure reliability and security of supply in the long-term. We proposed a similar project in the 2020-25 regulatory control period. However, in prioritising our program of work to account for our increased repex, and with the latest load and population forecasts for the area, we are now forecasting a different solution that we proposed in 2025-30, to be delivered in 2030, at a cost of $29.2 million

- **New feeder from Emerald to Blackwater –** the capacity of the existing network supplying Blackwater is already constrained. With continued strong load growth in the region, we are expecting that this will continue and worsen through the 2025-30 regulatory control period. Therefore, we are forecasting a requirement to invest in a new line between Emerald and Blackwater in 2031 at a cost of $40 million, with $23.1 million included in the 2025-30 regulatory control period, to increase network capacity and meet our Safety Net obligations

- **New feeder from Pandoin to Farnborough** – the Yeppoon and surrounding areas are forecasting strong population and load growth, resulting in the need to increase our sub-transmission capacity in the region. We are proposing the reinforcement in the upstream network between Pandoin and Farnborough to provide an alternative supply through to Yeppoon and increase its capacity, at a cost of $25 million, with $15.3 million included in the 2025-30 regulatory control period

- **North Toowoomba Substation establishment** – the area north of Toowoomba extending out to Highfields is forecast for significant expansion, with a master-planned residential and mixed commercial and industrial development over the next 15 years. In addition to population growth, this area will also see the connection of the Toowoomba Second Range Crossing as part of the Inland Rail project and development of the Toowoomba Hospital. The existing north Toowoomba substation has capacity limitations and end-of-life assets. As a result of the forecast growth, large load connections and aged substation assets we are forecasting the need for a new North Toowoomba substation at a cost of $12.5 million. We have already undertaken a RIT-D for this project and are forecasting establishment in 2026

- **Establish Bohle Plains new substation** – the west of Townsville continues to see significant housing development. We have been able to supply this growth with substations within the city, but this has resulted in long feeders being constructed. As growth increases, the cost of supplying from the existing substations will increase and the capacity of the substations will become constrained. We are forecasting the requirement for a new zone substation at Bohle Plains. We have catered for this requirement over the last two regulatory control periods, with a site already purchased and feeders constructed at 66kV already most of the way to the site. The forecast cost of this project is $19.6 million

- **Upgraded Chinchilla substation** – The town of Chinchilla is currently supplied through two substations with limited capacity. We are forecasting load growth for the area, which will require an increase in substation capacity. We are proposing to consolidate supply at Chinchilla T13 into a single, larger capacity substation that can securely supply the region over the long-term. The forecast cost of this project is $14.7 million, and

- **New Thabeban substation in the Bundaberg region** – as part of a major customer connection and general load and DER growth in the area, we are forecasting the requirement for a new 66/11kV substation at Thabeban to securely supply load in the region. The overall cost will be funded by a mix of ACS and SCS, with only the SCS portion of this expenditure appearing in our forecast expenditure. We have undertaken a RIT-D and are forecasting a requirement of $20.1 million to deliver the project in 2027.

5.5.2.2 Distribution growth

Similar to our sub-transmission expenditure, our distribution growth expenditure reduced in the 2015-20 and 2020-25 regulatory control period. However, strong population and customer growth, combined with increasing demand in the outer years of the current regulatory control period, is driving an increase in distribution feeder constraints on our network. As outlined in Chapter 4, this growth is forecast to continue. Accordingly, our Regulatory Proposal includes $215.4 million for ditirbution growth expenditure across the five years of the 2025-30 regulatory control period.

Estimated costs for this program are based on an assessment of the likely number of constraints we forecast in our network and an assessment of historic costs for projects of these types. This is then reflected in our Regulatory Proposal as an overall allocation for expenditure.

5.5.2.3 Clearance to ground and clearance to structure program

We have a compliance obligation to ensure that our assets maintain a clearance to ground and surrounding structures within statutory limits.[11] This legislative obligation is designed to maintain community safety, which is one of our key values.

We have a routine inspection program to identify spans of conductor that do not meet these obligations and a rectification program to resolve issues, as well as quarterly reporting obligations on our clearance remediation programs to the Queensland Electrical Safety Office. We are forecasting approximately $181.1 million for this program.

We acknowledge that this is a substantial investment in ensuring we meet our legislative obligations. As part of prioritising our program of work to ensure we are delivering balanced outcomes for customers and in response to the high level of clearance defects we have identified on our network, we have developed a ten-year clearance remediation program. Under this program, we rectified the most pressing clearance issues in the 2020-25 regulatory control period, and we will continue to rectify the outstanding issues identified in this period in the 2025-30 regulatory control period. We have worked with the Electrical Safety Office in developing this risk-based program to ensure we maintain a safe network for the community.

Estimated costs for this program are based on historic unit rates for delivering these types of work combined with our forecast number of clearance issues.

5.5.2.4 Reliability

We must meet the MSS targets set out in our Distribution Authority. MSS targets are feeder category-based reliability performance targets. Our Distribution Authority also includes obligations to improve the reliability of our worst performing 11kV feeders to address the impact on the customers connected to them.

We have assumed that the MSS for the 2020-25 regulatory control period will continue to be flat-lined and, as such, the augex forecast for the 2025-30 regulatory control period has been based solely on addressing worst performing feeder obligations. As the current MSS targets expire on 30 June 2025, the Queensland Government may set new targets which we would reflect in our updated forecasts in our Revised Regulatory Proposal.

Our augex forecast for the worst performing feeder improvement program has remained in line with the 2020-25 regulatory control period. Our forecast for this program is based on historical performance improvements on our network over the last 10 years.

Estimated costs for this program of $14 million for the 2025-30 regulatory control period are based on an assessment of the likely number of constraints we forecast in our network and an assessment of historic costs for projects of these types. This is then reflected in our Regulatory Proposal as an overall allocation for expenditure.

5.5.2.5 Resilience

Ergon Energy Network has long been required to deal with cyclone, storm, flood and bushfire events. We have an ongoing program to improve our network's capability to withstand these events so we can continue to reliably supply our customers with electricity. We acknowledge that the climate is changing and have assessed the ability of our existing expenditure program in meeting the likely flood and bushfire challenges in the coming regulatory control period. We propose an increase in our bushfire, flood, and storm resilience programs to $57.6 million for the 2025-30 regulatory control period. This program will improve the reliability of our network through

[11] Sections 207 and 208 of the Electricity Safety Regulation 2013 (Qld).

avoiding outages or improving our response time capability. It will also help prevent damage to our equipment from climate events and thereby reduce our emergency replacement requirements into the future. Our resilience program also includes new outage response capability to be delivered through mobile generators and mobile substations.

Estimated costs for this program are based on an assessment of the likely number of at-risk areas, utilising flood and bushfire mapping and historic outage data, and an assessment of historic costs for projects of these types. This is reflected in our Regulatory Proposal as an overall allocation for expenditure.

5.5.2.6 Grid communications, protection and network control

As part of operating a network, we have a component of system-enabling augmentation to ensure efficient, safe, and reliable operation for our customers. Investments include improvements to our telecommunications network to enhance our capacity to provide essential communications and to our protection systems to ensure reliable and safe operation of our network. Proposed investments for this category total $128.9 million for the 2025-30 regulatory control period.

5.5.2.7 Cyber security

With the increased threat of cyber-attacks, we are building on our existing cyber security foundations to address security at an enormous scale and exponential growth in attack surface area. This will require increasing usage of Artificial Intelligence and Machine Learning for automated detection and response along with converged operations management to better protect our assets, customers, and data at a cost of $9 million for the 2025-30 regulatory control period.

5.5.3 How this differs from our Draft Plan

Our augex has increase from the Draft Plan by $37 million. We have updated several key projects based our latest demand and population forecasts, with our subsequent augex being slightly higher than we forecast in our Draft Plan.

5.5.4 Delivering for our customers

Our forecast augex has been developed in accordance with our legislative and regulatory obligations and our Cost Benefit Framework and Principles to ensure that the strong population and household growth in regional Queensland is catered for, as well as improving the reliability of our network for the benefit of all customers.

5.5.5 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
Business Case Clearance to Ground & Structure program	5.5.01	Ergon - 5.5.01 - Business Case Clearance to Ground & Structure program - January 2024 - public
Business Case Distribution Feeder Augmentation	5.5.02	Ergon - 5.5.02 - Business Case Distribution Feeder Augmentation - January 2024 - public
Business Case New Feeder from Glenella to Planella	5.5.03	Ergon - 5.5.03 - Business Case New Feeder from Glenella to Planella - January 2024 - public
Business Case New Feeder from Emerald to Blackwater	5.5.04	Ergon - 5.5.04 - Business Case New Feeder from Emerald to Blackwater - January 2024 - public
Business Case New Feeder from Pandoin to Farnborough	5.5.05	Ergon - 5.5.05 - Business Case New Feeder from Pandoin to Farnborough - January 2024 - public

Document Name	Reference	File name
RIT-D North Toowoomba Substation Establishment	5.5.06	Ergon - 5.5.06 - RIT-D North Toowoomba Substation Establishment - January 2024 - public
Business Case Establish Bohle Plains Zone Substation	5.5.07	Ergon - 5.5.07 - Business Case Establish Bohle Plains Zone Substation - January 2024 - public
Business Case Upgrade Chinchilla zone substation	5.5.08	Ergon - 5.5.08 - Business Case Upgrade Chinchilla zone substation - January 2024 - public
RIT-D Establish Thabeban zone substation	5.5.09	Ergon - 5.5.09 - RIT-D Establish Thabeban zone substation - January 2024 - public
Business Case Bushfire and Flood	5.5.10	Ergon - 5.5.10 - Business Case Bushfire and Flood - January 2024 - public
Business Case Worst Performing Feeder Program	5.5.11	Ergon - 5.5.11 - Business Case Worst Performing Feeder Program - November 2023 - public
Reactive Distribution Augmentation	5.5.12	Ergon - 5.5.12 - Reactive Distribution Augmentation - January 2024 - public
Distribution Feeder Augmentation Maintain Reliability	5.5.13	Ergon 5.5.13 - Distribution Feeder Augmentation Maintain Reliability - January 2024 - public
New Mobile Generation	5.5.14	Ergon 5.5.14 - New Mobile Generation - January 2024 - public

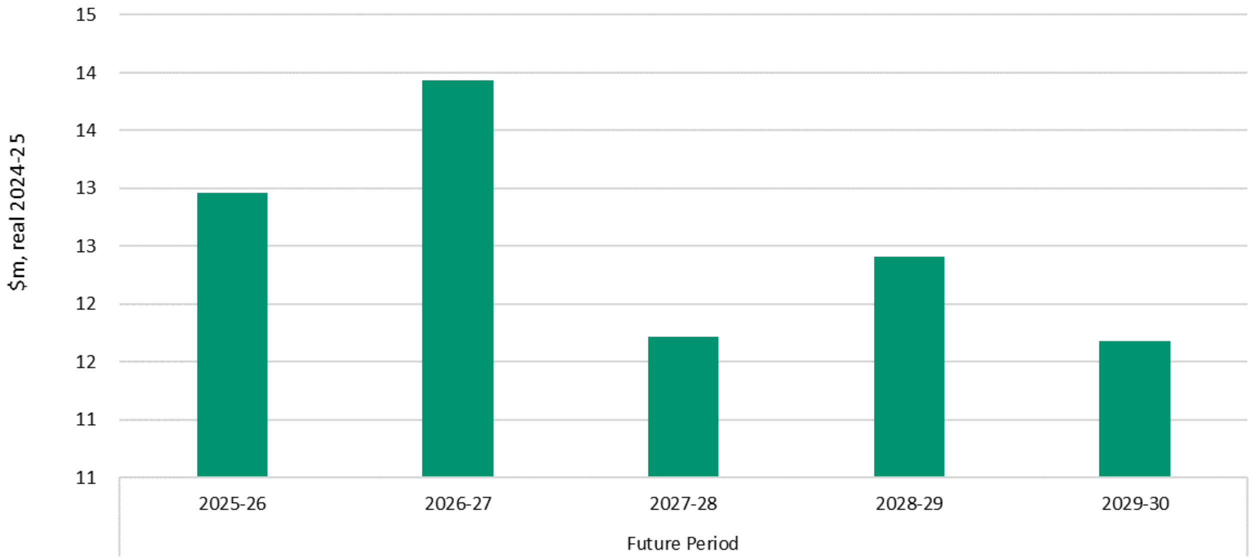
5.6 Distributed Energy Resources

To enable our customers to take up new technologies, such as electric vehicles and batteries, and to install more rooftop solar, we need to ensure that our network can handle the expected volume of energy exported back into the grid. This will allow our customers to benefit from their investments.

DER is a new category of expenditure for the 2025-30 regulatory control period, with expenditure of this nature being historically captured in augmentation. The term ‘DER’ can mean different things to different stakeholders. In the context of our Regulatory Proposal, this category of expenditure is related to augmentation of the network to resolve constraints associated with incorporating DER that exports energy into the distribution network. This could include rooftop solar but may also extend in time to electric vehicles with vehicle-to-grid capability, microwind or energy storage system exports.

Most of the feedback we received from stakeholders in response to our Draft Plan was that our focus on affordability was critical for our customers. We also received specific feedback on the pace of DER-related investment which was that we should take a proactive approach to allow customers to benefit from investing in new technologies. After careful consideration we have proposed a moderate approach to augmentation to provide for increased energy exports to our distribution network (for further information refer to section 5.6.4). Our proposed DER-related expenditure is $63 million over five years (refer to Figure 31).

Figure 31: DER-related capex between 2025 to 2030 ($m, real 2024-25)



The data supporting Figure 31 is provided in Table 34.

Table 34: DER-related capex between 2025 to 2030 ($m, real 2024-25)

	Future Period				
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
DER-related capex	13.0	13.9	11.7	12.4	11.7

5.6.1 Our forecasting approach

The 2025-30 regulatory control period is a critical period for Ergon Energy Network and its customers. By 2030, we are forecasting an almost 100 per cent increase in export through the middle of the day, exacerbating our minimum demand (or negative peak demand) challenges. Our DER Integration Strategy (Attachment 5.6.01) outlines our approach to forecasting DER-related expenditure. We have two key considerations in developing our DER-related expenditure:

- **Compliance** – there are two clear legislative obligations that have driven DER-related expenditure in this regulatory control period. Firstly, the obligation to provide a Basic Export Level (BEL) as part of the export services framework and secondly, to provide adequate network protection to enable the clearance of faults in our network (which becomes more difficult with power flows in the network changing due to export services), and
- **Cost-benefit Analysis -** in accordance with our Cost Benefit Framework and Principles, we have assessed the need for investment in systems, demand management, and tariff design as an alternative to traditional network solutions, and/or traditional network solutions to alleviate customer export curtailment in line with the AER's *Customer Export Curtailment Value* (CECV) and carbon emissions abatement.

5.6.2 Summary of proposed investments

As our customers install more rooftop solar and adopt new technologies, such as electric vehicles and batteries, there is an increase in the volume of energy exported back into the grid. We invest in our network to enable DER to be connected and to export. Expenditure against the four main categories of DER-related capex is provided in Table 35.

Table 35: DER-related capex by category between 2025 to 2030 ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Dynamic connections	2.1	1.3	0.0	0.0	0.0	**3.4**
Grid visibility	6.2	6.9	7.1	7.9	7.8	**35.9**
Hosting capacity	2.3	2.3	2.3	2.4	2.4	**11.7**
Network protection	2.3	3.5	2.3	2.1	1.5	**11.7**
Total[1]	**13.0**	**13.9**	**11.7**	**12.4**	**11.7**	**62.7**

Note 1: Totals may not add due to rounding.

5.6.2.1 Dynamic connections

A dynamic connection is a new smarter connection option for solar PV, battery and electric vehicle charging installations. It allows more of our customers' excess energy to be exported, while ensuring we maintain a safe and reliable electricity network. Dynamic connection involves us monitoring the capacity of the local electricity network, calculating how much excess energy can be exported to the grid and sending a signal to our customers' inverters with a dynamic connection to maximise their export to the network based on available network capacity.

The 2025-30 regulatory control period will see the continued implementation of dynamic operating envelopes[12] and the rolling out of dynamic connections to manage the forecast significant increase in DER. We have proposed $3.4 million to finalise the implementation of our Low Voltage Distributed Energy Resource Management System (LVDERMS).

5.6.2.2 Grid visibility

To expand our capacity to support growing volumes of DER we will need to transform the distribution network into a more intelligent and dynamic grid. Greater access to timely data and information to determine the electrical status of the low voltage network will be essential for us to send the right control signals to manage these resources in real time.

Typically, our low voltage network assets have limited real-time data available around the power flows on the network. While LVDERMS can operate using limited data, it means that we would have to be more conservative in our approach to managing network voltage and thermal constraints, which would result in curtailing customer exports more than would be necessary if we had greater visibility of our network power flows. If we remain at the same level of limited real-time data on the electrical status of the low voltage network, we would be required to invest more in increased hosting capacity because of this high level of curtailment (and associated CECV). Higher curtailment would also have a negative environmental impact as a reduction in the level of renewable energy export would reduce the level of avoided carbon emissions.

[12] Dynamic operating envelopes vary limits over time, based on the capacity or other capability of the network in near real time. This includes, for example, export and import limits at the local network or power system as a whole.

Our Export Service Strategy outlines the benefits to customers of having more network visibility to unlock export. There are four elements to this expenditure:

- **Distribution transformer monitors** – establishing grid visibility on transformers exhibiting high export penetration. These monitors have benefits beyond DER integration, including reduced response time to outages, resulting in improved reliability and planning functionality uplift from the use of the data
- **Low voltage monitors** - installing a small quantity of low voltage monitors to measure power quality at the customer's premises. This investment is part of our Smart Meter Data Acquisition step change business case, and provides safety, reliability and financial benefits in addition to the DER integration case
- **Recloser upgrades** – improved remote visibility of protection devices, including enhancement of our existing line recloser fleet and in some cases, replacement and installation to improve our network visibility and enhance safety and reliability, and
- **Telemetry hub expansion –** this expansion will improve our capability to have data delivered and analysed as part of our state estimation and dynamic operating envelopes framework.

5.6.2.3 Hosting capacity increases

Our overall forecast expenditure for hosting capacity increases is around $11.7 million. Having enabled dynamic connections and grid visibility to effectively integrate DER into our network, hosting capacity increases are typically the last option in our expenditure. There are two elements to our hosting capacity increase:

- **BEL** - as discussed earlier, we have an obligation to both set a BEL and then provide network capacity to the BEL for all customers. We have studied our network's capability to host export services and have determined that a reasonable BEL is 1.5kW per customer. While this is a level of export that we can provide to most customers, we will still need to invest in some areas of the network to ensure all customers can access this level of export, and
- **CECV / carbon emissions** - where there are network constraints, for customers on a dynamic connection or with a newer style inverter with volt-var or volt-watt curtailment, customer export will be curtailed. Where this curtailment leads to a CECV and carbon emissions value higher than the equivalent expenditure to alleviate the constraint, we invest to unlock the export for all customers.

5.6.2.4 Protection upgrades

Protection systems isolate networks when there are faults that can cause safety risks to the community and our staff, or damage to our network. These systems were designed to operate for power flows from generators to our customers. With customers now being able to provide generation into the network, some of our protection systems are unable to provide adequate protection. Our investment in this element of our DER integration is around $11.7 million.

5.6.3 How this differs from our Draft Plan

Our DER-related expenditure has reduced from our Draft Plan by $11 million. We have been able to align our protection upgrades with other projects, reducing overall expenditure in our Regulatory Proposal. Our investments in hosting capacity, grid visibility and dynamic connections remains unchanged.

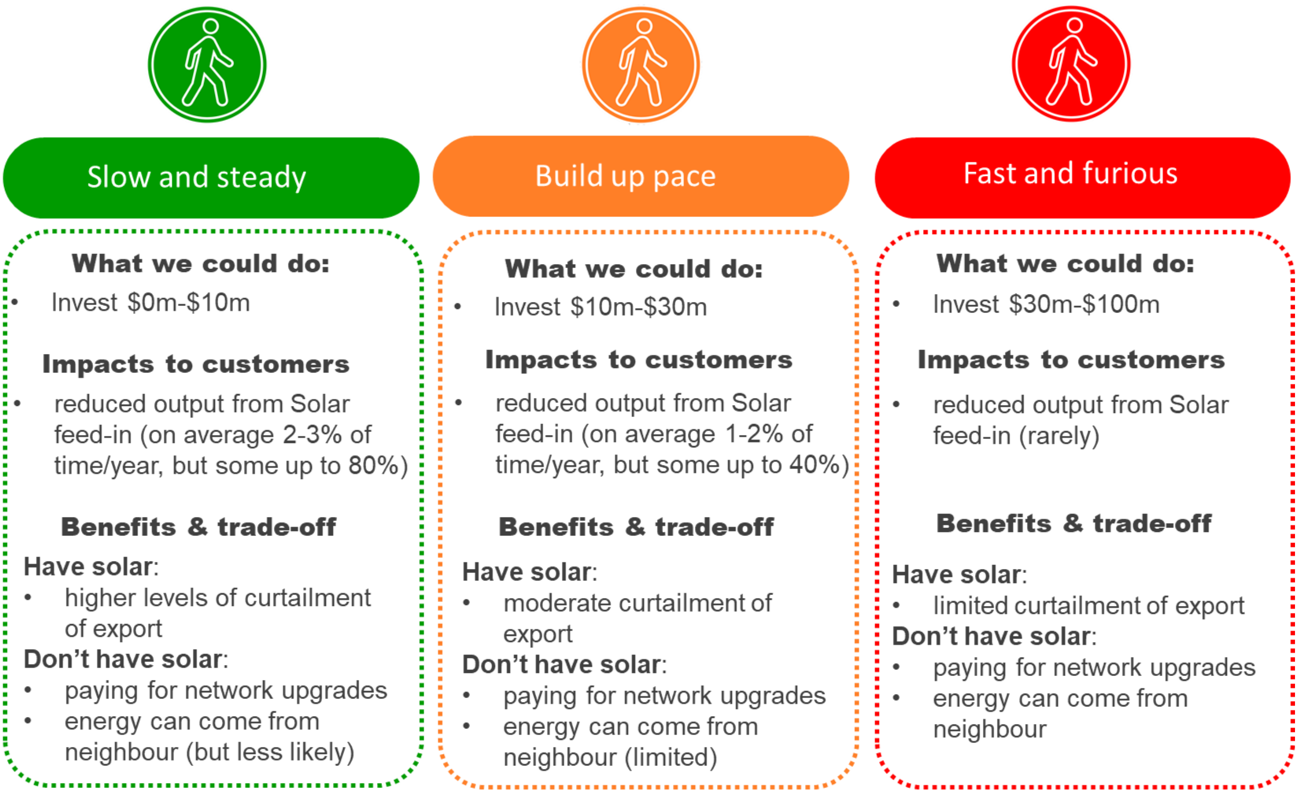
5.6.4 Delivering for our customers

Our dynamic connections framework allows us to maximise the utilisation of existing assets, while also increasing the capability for our customers to export. Without a level of coordination of export services, the strong growth in export uptake we have forecast will mean significant network expansion will be required.

Our tariff strategy of providing export at no cost for those with a dynamic connection or an export charge and reward for those without a dynamic connection (for new customers from 2025 and existing customers from 2028) provides our customers with choice. Those who are willing to allow us to reduce their export at times of constraint will not be required to pay an export charge, while those who want to export relatively free of constraints can choose to pay the export charge.

We discussed three scenarios around the potential pace of investment and what benefits and trade-offs these would have in two sessions with a focus group of residential customers (refer to Figure 32).

Figure 32: DER investment options



In the first session, our customers told us that they were interested in connecting solar power and purchasing electric vehicles in the future and were open to reducing their electricity consumption at peak demand times. While some participants were in favour of us taking a proactive approach to the transition to facilitating renewable energy, other participants cautioned against this causing an increase in costs for all customers, particularly for the most vulnerable. When presented with the pace of change options around DER investment, most participants' preferences were between 'build up pace' and 'fast and furious'.

In our second session, we presented more specific information on the costs and potential bill impacts of these three options. Participants were still in favour of us taking a proactive approach, with the preferred option of most participants shifting to the ‘fast and furious’ option.

The majority of the feedback we received from stakeholders to our Draft Plan was that our focus on affordability was critical for our customers. To ensure that we do not create undue cost pressures on customers, our Regulatory Proposal includes the ‘build up pace’ investment option, which forms part of the proposed $63 million in DER-related expenditure. We acknowledge that this level of investment is less than our focus group recommended. However we have attempted to balance their views with the more general feedback we received from our customers and stakeholders on the Draft Plans.

5.6.5 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
DER Integration Strategy	5.6.01	Ergon - 5.6.01 - DER Integration Strategy - January 2024 - public

5.7 Connection Expenditure

The growth in regional Queensland’s population has been strong since the Covid-19 pandemic and is forecast to continue to grow through the 2025-30 regulatory control period. Population growth in regional Queensland drives the volume of new home and business customer connections to our network and we are forecasting an annual average growth rate for new customer connections of 1.6 per cent during 2025-30. The investment of $321 million in net connection expenditure (connex) reflects the expected strong population growth in regional Queensland.

The costs associated with connecting new customers to the network are either funded directly by customers (as an ACS) or recovered from all customers through their network charges (as a SCS).

For those connection costs that are recovered directly from customers as an ACS (for example, large sites that have dedicated network assets, such as a major stadium, a hospital or industrial site), customers pay directly for their connection costs and these costs are not included in our network charges recovered from all customers. Contributions from customers can be in direct funding (Type 1 contributions) or in contributed or gifted assets (Type 2 contributions).

Where Ergon Energy Network incurs costs to connect new residential and small business customers, or to extend and augment the network to allow for the new connected load to be transported via our grid, we share these costs across the entire customer base through our network charges. This is referred to as ‘net connex’.

For the 2025-30 regulatory control period, we are forecasting net connex of $321 million as set out in Table 36. This is approximately the same amount of net connex we expect to spend in the 2020-25 regulatory control period.

Table 36: Forecast net connex between 2025 to 2030 ($m, real 2024-25)

	Future Period					
$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Net Connex	59.8	62.3	64.4	66.6	68.1	**321.2**

Note 1: Total may not add due to rounding.

5.7.1 Our forecasting approach

Ergon Energy Network's connection and contribution expenditure forecasts for the 2020-25 regulatory control period were developed using a simple top-down methodology where we trended a base year (2018-19) of connex over the 2020-25 regulatory control period. The escalations applied to the base year were based on historical and forecast trends in connection numbers. While this forecast was accepted by the AER, it is acknowledged that the forecasting methodology could be improved.

Consequently, for the 2025-30 regulatory control period, we have adopted a robust econometric forecast modelling approach to estimate our connection and contribution expenditure forecasts, consistent with forecasting approaches used by other distributors across the NEM. This is aligned with our customers' expectations that we will employ best practice in our forecasting approaches to ensure that they are paying a fair and reasonable level for net customer connections.

We undertook a comprehensive approach to developing our forecast 2025-30 net connex, which included consideration of:

- historical and forecast customer numbers
- connection volume forecasts
- government policy, and
- demographic, economic and construction outlooks.

Our net connex forecast is supported by analysis of connection volumes by type and net connex by type from an independent external consultancy firm (FTI Consulting) with expertise in modelling construction expenditure forecasts.

As a first step, our connex model estimates connection volumes, using demographic forecasts, forecasts in household size and growth in commercial activity. As a second step, the model establishes a statistical relationship between net connex forecasts and connection volume forecasts.

While a pure econometric relationship between volumes and net connex could be estimated, the relatively short time-series for connex and its volatility in certain categories, meant that a more nuanced approach was needed to determine the prudency of the connex forecasts.

In summary, the overall approach taken to develop our forecasts includes:

- statistical analysis of the historical relationship between connection volumes and connex for residential, commercial and industrial connections
- determining the drivers of volatility in historical capex per connection, particularly for commercial and industrial connections, and to determine the most appropriate relationship for the forecast period
- historical analysis using FTI Consulting's construction industry tracker and major projects database to determine the highest growth sectors during the historical period (i.e for residential, whether growth was concentrated in houses, apartments, new developments, and for commercial and industrial, whether growth was most prominent in retail, commercial or industrial), and alignment of these shares to the historical data to explain costs
- using FTI Consulting's construction forecasts and major project forecasts to estimate the shares of development over the next decade

- Ergon Energy Network's customer number forecasts,[13] and
- incorporation of any significant initiatives or events (e.g. the *Queensland Jobs and Energy Plan*).

Further details on the methodology used to develop our forecast 2025-30 net connex is provided in Attachment 5.7.01.

5.7.2 Summary of proposed net connex

Forecast net connex is driven by the forecast level and geographic area of new home and business connections. It is important to have a robust and rigorous estimate of new connections as possible to ensure that customers do not pay more than necessary for net connex. To determine the optimal level of investment we consider population growth and household size.

Over the current regulatory control period, Queensland experienced a period of negative international migration in 2020-21, partially offset by interstate migration into Queensland in 2021-22, due to border restrictions introduced in response to the Covid-19 pandemic. With the reopening of Australia's international borders, it is expected population in regional Queensland will see a steady growth between 2022-23 and 2029-30. Figure 33 to Figure 38 show population forecasts for major centres in regional Queensland.

Figure 33: Cairns population forecast

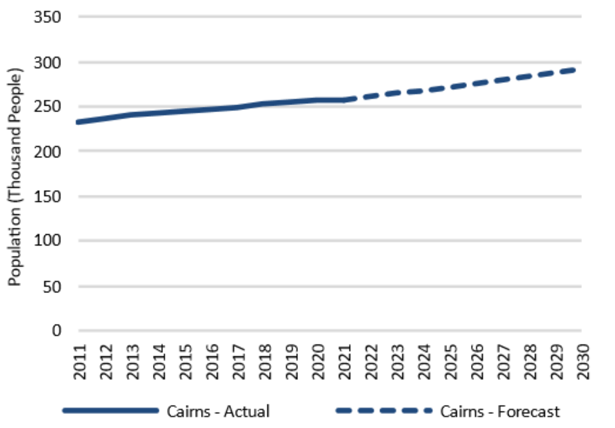
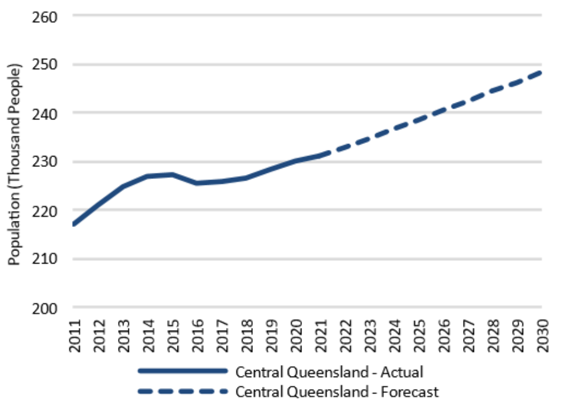


Figure 34: Central Queensland population forecast



[13] Ergon Energy Network's customer number forecasts are discussed in Chapter 4.

Figure 35: Darling Downs population forecast

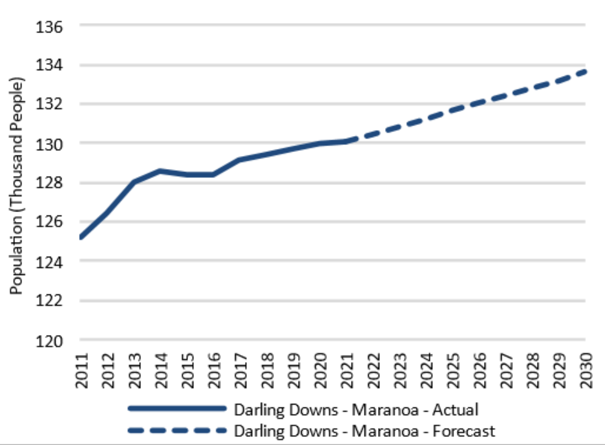


Figure 36: Mackay population forecast

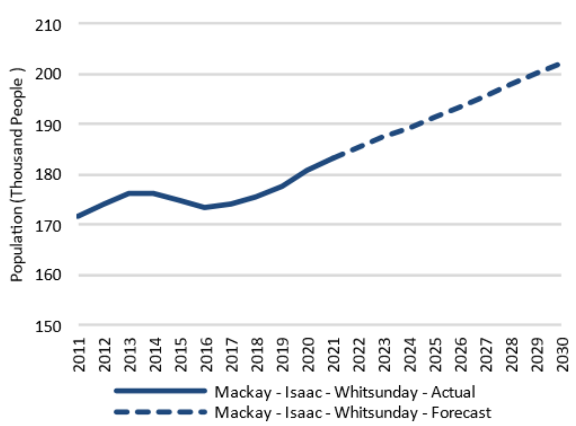


Figure 37: Townsville population forecast

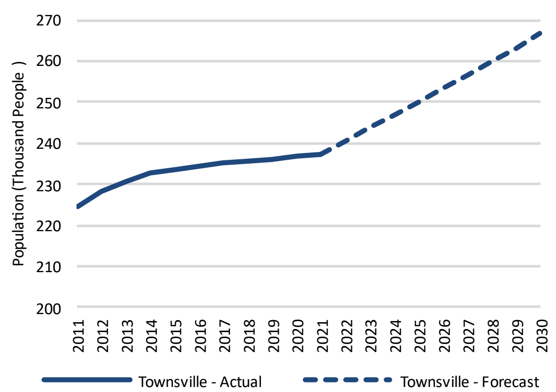
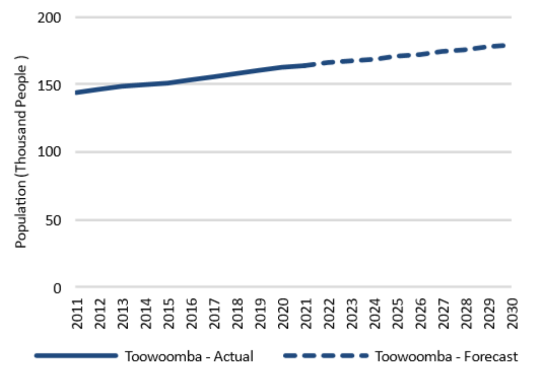


Figure 38: Toowoomba population forecast

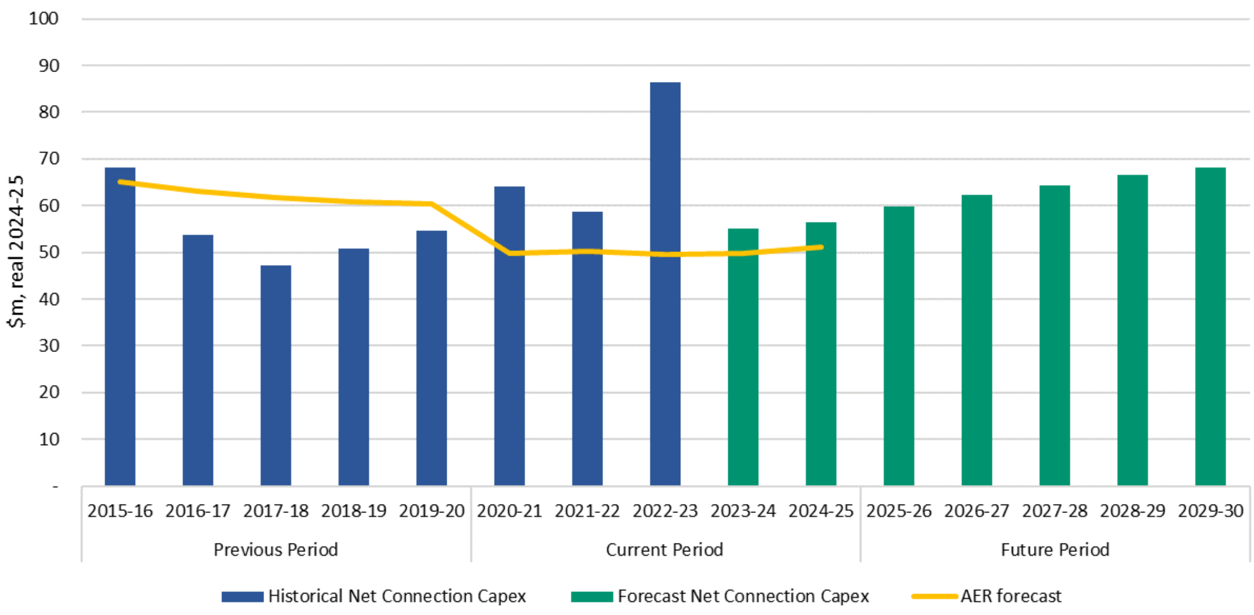


Source: Australian Bureau of Statistics

Another key driver of connections is the size of households. With an ageing population, household size in regional Queensland has been gradually declining, resulting in a larger number of single or two person households. Over time we have seen household size going from 2.7 persons per household in 2016, to 2.6 in 2021 and it is expected to continue its downward trend to 2.5 persons per household in 2030.

These economic and demographic drivers are expected to result in a steady growth in net connex over the next seven years (refer to Figure 39).

Figure 39: Net connex between 2015 to 2030 ($m, real 2024-25)



The data supporting Figure 39 is provided in Table 37 and Table 38.

Table 37: Historical net connex ($m, real 2024-25)

	Previous Period					Current Period		
$m, real 2024-25	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**
AER forecast	65.1	63.1	61.7	60.9	60.3	49.7	50.2	49.6
Net connex	68.2	53.9	47.2	50.8	54.7	64.2	58.7	86.5

Table 38: Forecast net connex ($m, real 2024-25)

	Current Period		Future Period				
$m, real 2024-25	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
AER forecast	49.9	51.2	n/a	n/a	n/a	n/a	n/a
Net connex	55.1	56.5	59.8	62.3	64.4	66.6	68.1

The net connex estimated for 2022-23 to 2024-25 is higher than the AER forecast due to the unanticipated and unpredictable impact of Covid-19 on migration into Queensland and the historically low interest rates, resulting in an increase in new constructions.

Table 39 presents our forecast for net connex and cash contributions treated as SCS which, when added together, make our gross connex.

Table 39: Forecast gross connex between 2025 and 2030 ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Net connex	59.8	62.3	64.4	66.6	68.1	**321.2**
Cash contribution	17.6	16.9	16.9	16.8	16.6	**63.2**
Gross connex	77.5	79.3	81.3	83.3	84.7	**384.4**

Note 1: Totals may not add due to rounding.

5.7.3 How this differs from our Draft Plan

The changes to the connex forecasts from our Draft Plan include:

- an update to the customer number forecasts, and
- an update in Queensland demographic forecasts.

This has resulted in a 0.7 per cent increase on the forecast net connex included in the Draft Plan.

5.7.4 Delivering for our customers

As part of our customer and stakeholder engagement we presented our proposed connex forecasts in our Draft Plan. We note that we did not receive any specific comments on this matter.

Our forecast connex has been developed in accordance with robust econometric modelling to ensure that the strong population and household growth in regional Queensland is catered for and benefits all customers wishing to connect to our network. Improvements in our forecasting approach mean that customers will not pay more than is necessary for net connex and can have confidence that our forecast has been subject to rigorous, independent analysis and review.

5.7.5 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
FTI Consulting Methodology Report Connections Volume and Connex Forecasts for 2025-3	5.7.01	Ergon - 5.7.01 - FTI Consulting Methodology Report Connections Volume and Connex Forecasts for 2025-30 - January 2024 - public
Connection Policy 2025-30	5.7.02	Ergon - 5.7.02 - Connection Policy 2025-30 - November 2023 - Public
Connex forecast model	5.7.03	Ergon - 5.7.03 - Connex forecast model – January 2024 - public

5.8 Information, Communications and Technology

We must maintain our non-network ICT[14] systems and capability to enable our business to operate effectively and safely, to allow our customers to interact with us when and how they choose to, and to allow our staff to have the information they need when they need it. This enables us to deliver a safe and reliable electricity supply for our customers.

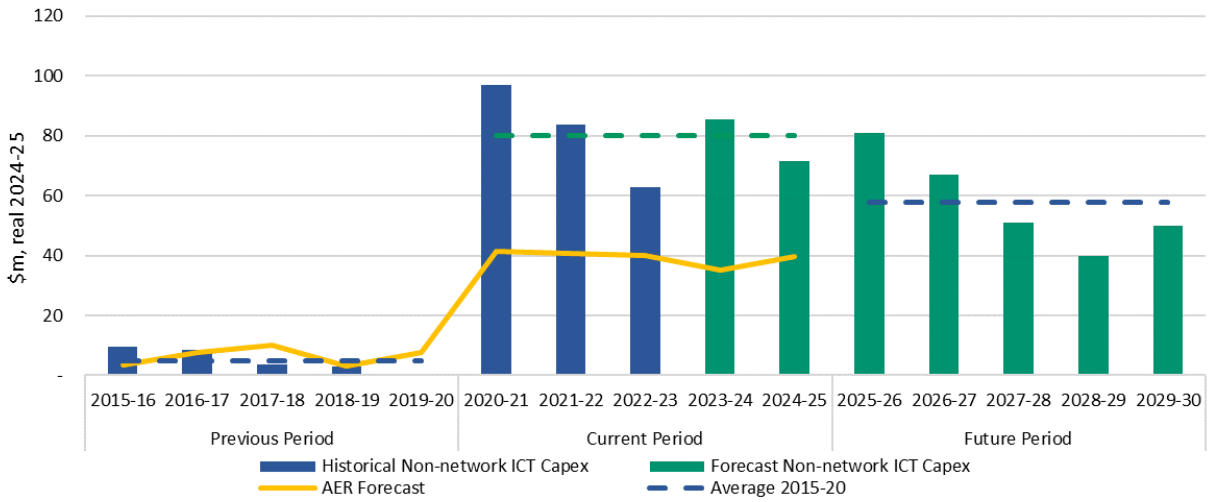
We have heard from our customers and stakeholders that they expect us to keep pace (not behind or in advance, just at pace) with the expected industry transition. We also recognised the AER's feedback to other distributors that investment too far in advance of need is not warranted, nor prudent or efficient.

Therefore, our proposed non-network ICT program for 2025-30 focuses on two main aspects:

- ensuring that our systems are maintained for sustainability, cyber security, compliance and operational safety, and
- keeping pace with the industry transition through prudent and efficient investment to allow for appropriate scaling for the expected level of growth, and, in some cases, new or expanded ICT capability.

During the current 2020-25 regulatory control period, we are delivering a major transformation and consolidation of core systems and business processes, with some significant parts due to be delivered in 2024-25. In recognition of the significant ICT investment we have made during the current period, we propose a 28 per cent reduction in non-network ICT capex for the 2025-30 regulatory control period. This investment of $288 million over five years reflects our shift from a major transformation focus to one of on-going maintenance, particularly for our Assets and Works Management and Digital Core systems and platforms. Consequently, we are forecasting an approximate $22.4 million reduction in average annual capex spend for ICT (refer to Figure 40). For further information on our historical ICT performance refer to Attachment 5.3.11.

Figure 40: Ergon Energy non-network ICT capex ($m, real 2024-25)



Note: ICT services were treated as an overhead prior to 2020 due to the corporate structure at that time. From 2020-21 ICT capex is included in the non-network capex category.

[14] Non-network ICT are those ICT assets (defined as the devices, applications and systems that combined allow for interaction with the digital world) that are not integrated or embedded in primary network assets. Network ICT refers to those ICT assets that are integrated or embedded in primary network assets, such as substations and lines, and generally relates to the control and operating of the network. Network ICT expenditure is contained in network capex.

The data supporting Figure 40 provided in Table 40 and Table 41.

Table 40: Historical non-network ICT capex ($m, real 2024-2025)

	Previous Period					Current Period		
$m, real 2024-25	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
AER forecast	3.4	7.5	10.0	3.1	7.7	41.3	40.8	39.9
Non-network ICT	9.4	8.6	3.6	2.8	0.2	96.9	83.6	62.8

Table 41: Forecast non-network ICT capex ($m, real 2024-2025)

	Current Period		Future Period				
$m, real 2024-25	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
AER forecast	35.2	39.5	n/a	n/a	n/a	n/a	n/a
Non-network ICT	85.3	71.5	81.1	66.9	50.9	39.6	49.8

5.8.1 Our forecasting approach

The non-network ICT expenditure forecast was developed through consistent methods that ensures the forecasts are prudent and aligns with enabling business priorities.

For our non-network ICT capex equivalent, business cases using cost-benefit analysis were developed for each core area of our ICT capability – Asset and Works Management, Integrated Grid Planning, Customer, Digital Core, Data and Intelligence, Digital Foundations and Cyber Security (refer to Attachments 5.8.02 to 5.8.08).

A mix of bottom-up and top-down methods was applied to estimate the costs for the initiatives in the business cases. Forecasts were estimated using a mix of historical costs, knowledge of recent market procurement for equivalent services and products, as well as specialist advice from subject-matter experts and vendors. Contingency has not been included in the forecasts.

We also considered our Digital Asset Management Guidelines – Infrastructure Renewal Timelines[15] to determine the frequency of forecast evergreening spend on a range of hardware and software assets.

The opex directly associated with the initiatives is also documented in the business cases for increased transparency but was not included in the overall capex modelling for this Regulatory Proposal.

We also conducted:

- **trend analysis:**
  - analysing actual expenditure in the current regulatory control period compared to proposed future regulatory control period expenditure to ensure the investment proposal is within parameters of historical submissions and delivery capability, and
  - testing the forecast against financial assumptions and non-network ICT plans to ensure consistency of forecast across the investment proposals

[15] Refer to the Non-Network ICT Plan – section 43 (Non-network ICT Asset Lifecycle Management).

- **benchmarking:**
  - running comparisons between opex and capex forecasts with the previous regulatory control period submission with escalation applied to test prudency, and
- **top-down challenge:**
  - ensuring detailed analysis of business case estimates were undertaken through oversight and challenge sessions with Senior Management and Finance Partners, and
  - using stakeholder consultation to confirm that investment approaches are sound. This involved extensive internal reviews and consultation, and RRG and Customer Focus Group sessions.

Trend analysis, benchmarking and cost-benefit analysis were undertaken for recurrent expenditure. Top-down challenge and cost-benefit analysis were undertaken for non-recurrent expenditure.

Our standard governance processes applied throughout the non-network ICT forecasting process, which consisted of:

- regulatory process gates, including reviews and challenge sessions
- internal non-network ICT executive approvals, and
- Executive Management Committee approvals.

The usual governance processes will be applied to the implementation of the initiatives in the business cases. The Digital Governance Framework is explained in the Non-Network ICT Plan 2025-30 (Attachment 5.8.01).

5.8.2 Summary of proposed investments

Our non-network ICT investment proposals for 2025-30 were developed to keep pace with the industry transition and modernise our customers' experience. The investments focus on:

- improving customer self-service options, and enhancing and automating customer connection applications and service delivery
- maturing our capabilities in cyber security to protect the operation of our network, confidentiality of sensitive information and availability of critical business systems
- delivering the digital tools, platforms and capabilities to support our workforce in the field and office, and
- maintaining our efficient, reliable, secure and smart digital foundation.

These investments will enable efficient business operations, improved customer service and the ongoing safety management of our distribution business. A summary of the proposed non-network ICT investments is provided in Figure 41 and more detail can be found in the non-network ICT business cases.

Figure 41: Proposed non-network ICT investments for 2025-30

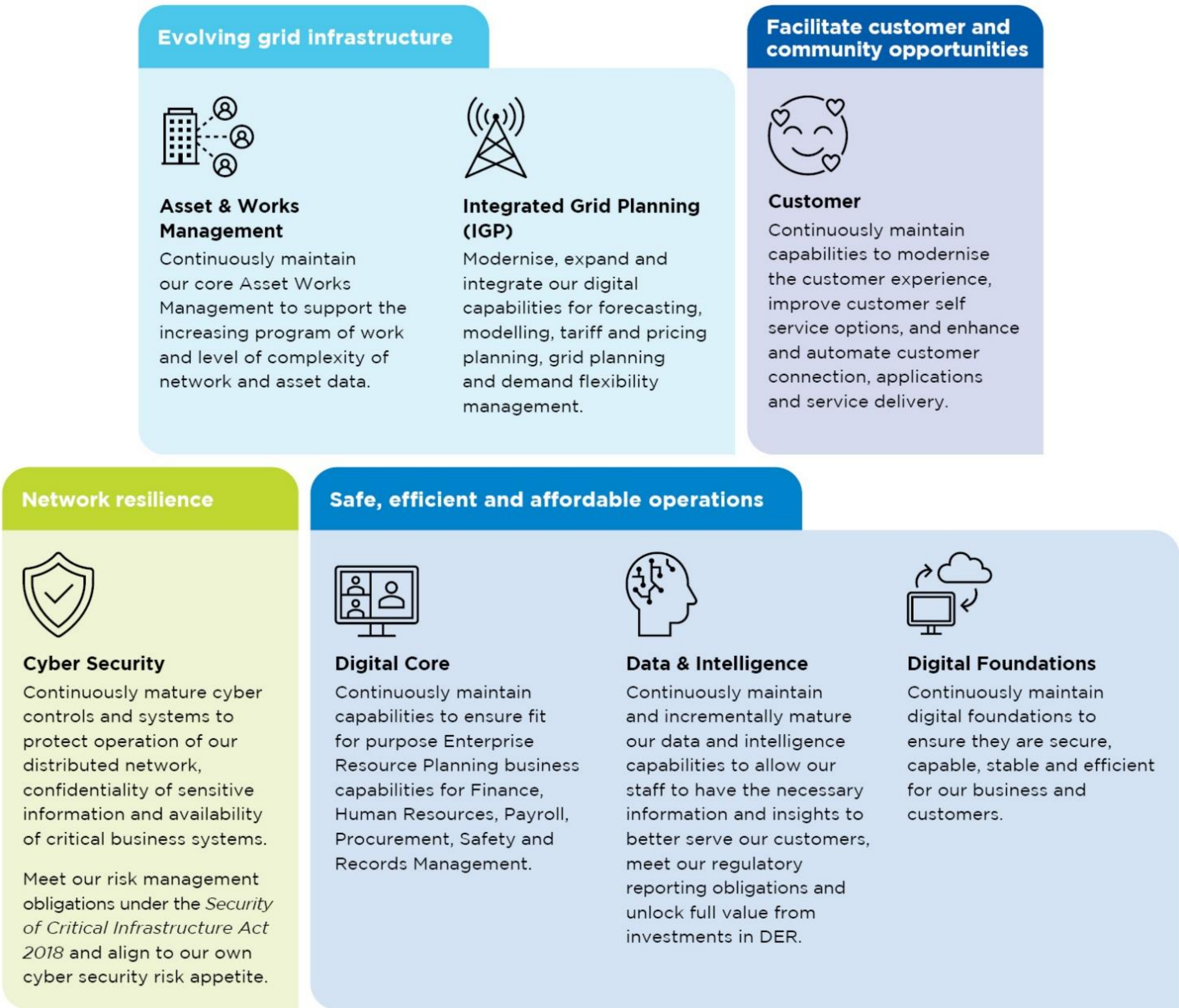


Table 42 and Table 43 outline the breakdown of the non-network ICT capex into the AER's capex categories for ICT. There is an increase in recurrent capex as per our move to a continuous recurrent cycle of regular upgrades to applications and technologies as opposed to large-scale non-recurrent ICT asset replacement programs. This approach was developed based on lessons learned from our experience in implementing a large-scale, transformational ICT program. A key lesson learned was that it becomes more exponentially challenging to transform and consolidate legacy applications the longer they are left. In addition, operating legacy applications continuously increases our security risk posture. Consequently, we have consciously planned for a continuous recurrent cycle of regular upgrades to non-network ICT applications and technologies (referred to as 'evergreening') to reduce our cyber security and project delivery risks.

Table 42: Breakdown of historical non-network ICT capex ($m, real 2024-25)

	Previous Period					Current Period		
$m, real 2024-25	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**
Non-recurrent						**87.9**	**74.2**	**46.7**
Maintain						24.6	30.2	39.5
Comply						7.2	5.2	0.0
New / Expanded						56.2	38.8	7.2
Recurrent	**9.4**	**8.6**	**3.6**	**2.8**	**0.2**	**9.0**	**9.4**	**16.1**
Total[1]	**9.4**	**8.6**	**3.6**	**2.8**	**0.2**	**96.9**	**83.6**	**62.8**

Note 1: Totals may not add due to rounding.

Table 43: Breakdown of forecast non-network ICT capex ($m, real 2024-25)

	Current Period		Future Period				
$m, real 2024-25	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Non-recurrent	**55.8**	**60.1**	**30.7**	**27.0**	**23.0**	**18.5**	**20.6**
Maintain	45.3	52.3	19.3	16.7	13.4	11.1	13.2
Comply	0.7	1.0	5.0	5.1	5.8	5.0	4.9
New / Expanded	9.8	6.7	6.3	5.2	3.8	2.5	2.5
Recurrent	**29.4**	**11.5**	**50.3**	**39.9**	**27.8**	**21.1**	**29.1**
Total[1]	**85.3**	**71.5**	**81.1**	**66.9**	**50.9**	**39.6**	**49.8**

Note 1: Totals may not add due to rounding.

5.8.3 How this differs from our Draft Plan

The investment proposals for non-network ICT capex have largely remained unchanged between the Draft Plan and this Regulatory Proposal. However, there was an error in the calculation of the non-network ICT capex for the Draft Plan, which resulted in an under-estimation of SCS capex for Ergon Energy Network. This error has been rectified, resulting in an increase of $37 million for non-network ICT capex in this Regulatory Proposal.

5.8.4 Delivering for our customers

The proposed capex for non-network ICT is primarily driven by the need to prudently maintain our systems and capability in line with established non-network ICT asset lifecycle management practices to enable our business to be more efficient, deliver for our customers and ensure the safety of our staff and communities.

Due to the technical nature of these investments, we primarily focused our customer engagement on non-network ICT capex with the RRG. We provided the RRG with a deep dive on our cyber security investment options and two complete business cases (Customer and Digital Foundations) for their review and feedback. The RRG was particularly focused on the customer benefits of our proposals and ensuring that we had appropriate governance frameworks in place for our non-network ICT investment.

We had heard through our business-as-usual engagement channels that customers want support to navigate the transition to a low emissions future, especially around how to reduce their energy costs through energy efficiency or investment in DER. In August 2023, we explored with a focus group of customers what type of support we could provide (e.g. advice through our call centre or on-line channels). We then requested input from a wider audience through our Draft Plan released in September 2023. The majority of respondents were comfortable with us providing on-line tools.

In October 2023 we presented to our customer focus group on optionality in customer experience and to test their preference for investment. The response received showed unanimous support for the full suite of proposed customer initiatives, which included investment in enhancing call centre technologies and broader digital online channels and assisting customers by providing online tools. We have also considered the overarching view of customers that affordability is their main priority and therefore have focused on improving communication channels of choice (e.g. web site, contact centres) and keeping customers informed through emergency and major events. We have also taken on board customers' feedback about benefits to the organisation and incorporated additional information on benefits into our business cases.

5.8.5 Supporting documentation

The following documents support this section:

Document Name	Reference	File name
Non-network ICT Plan 2025-30	5.8.01	Ergon - 5.8.01 - Non-network ICT Plan 2025-30 - January 2024 – public Ergon - 5.8.01 - Non-network ICT Plan 2025-30 - January 2024 - confidential
Business Case – ICT Asset and Works Management	5.8.02	Ergon - 5.8.02 - Business Case ICT Asset and Works Management - January 2024 - public Ergon - 5.8.02 - Business Case ICT Asset and Works Management - January 2024 – confidential
Business Case – ICT Customer	5.8.03	Ergon - 5.8.03 - Business Case ICT Customer - January 2024 - public Ergon - 5.8.03 - Business Case ICT Customer - January 2024 – confidential
Business Case - Cyber Security	5.8.04	Ergon - 5.8.04 - Business Case Cyber Security - January 2024 – confidential
Business Case – ICT Data & Intelligence	5.8.05	Ergon - 5.8.05 - Business Case ICT Data & Intelligence - January 2024 - public Ergon - 5.8.05 - Business Case ICT Data & Intelligence - January 2024 – confidential
Business Case – ICT Digital Core	5.8.06	Ergon - 5.8.06 - Business Case ICT Digital Core - January 2024 - public Ergon - 5.8.06 - Business Case ICT Digital Core - January 2024 – confidential
Business Case – ICT Digital Foundations	5.8.07	Ergon - 5.8.07 - Business Case ICT Digital Foundations - January 2024 - public Ergon - 5.8.07 - Business Case ICT Digital Foundations - January 2024 - confidential
Business Case – ICT Integrated Grid Planning	5.8.08	Ergon - 5.8.08 - Business Case ICT Integrated Grid Planning - January 2024 - public Ergon - 5.8.08 - Business Case ICT Integrated Grid Planning - January 2024 – confidential

Document Name	Reference	File name
ICT Post Implementation Review Summaries	5.8.09	Ergon - 5.8.09 - ICT Post Implementation Review Summaries - November 2023 – public Ergon - 5.8.09 - ICT Post Implementation Review Summaries - November 2023 – confidential
Business Case – ICT Common Glossary	5.8.10	Ergon – 5.8.10 – Business Case ICT Common Glossary – January 2024 - public
Non-network ICT Forecast Model	5.8.11	Ergon - 5.8.11 - Model Non-network ICT Forecast - January 2024 – confidential

5.9 Other non-network capital expenditure

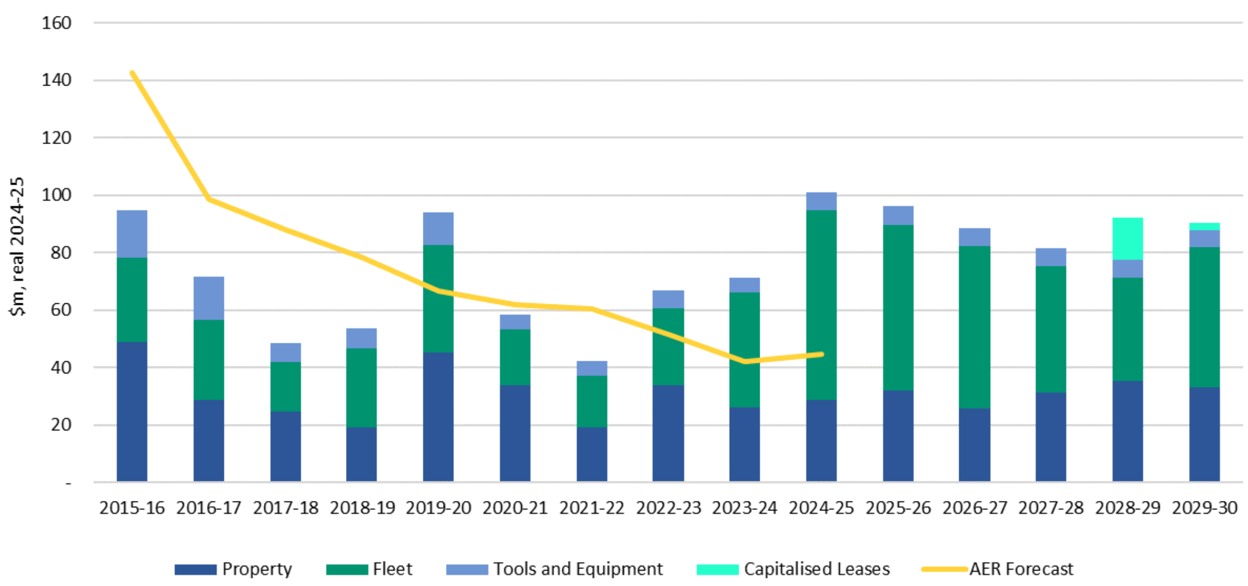
To meet customers' expectations for a safe and reliable electricity supply, we must equip our workforce with the right buildings, vehicles, tools and equipment so that they can efficiently deliver electricity to customers. To do this we invest in four categories of support costs: property, fleet, tools and equipment, and capitalised leases.

Our proposed expenditure over the 2025-30 regulatory control period includes:

- $157 million on non-network property, representing an 11 per cent increase on our expected spend in the 2020-25 regulatory control period
- $243 million on fleet expenditure, representing a 42 per cent increase on our expected spend in the 2020-25 regulatory control period
- $32 million on tools and equipment expenditure, representing a 17 per cent increase on our expected spend in the 2020-25 regulatory control period, and
- $17 million on capitalised leases, which is a new capex category for the 2025-30 regulatory control period.

The yearly breakdown of other non-network capex is provided in Figure 42.

Figure 42: Other non-network capex between 2015 to 2030 ($m, real 2024-25)



The data supporting Figure 42 is provided in Table 44 and Table 45.

Table 44: Historical other non-network capex ($m, real 2024-25)

	Previous Period					Current Period		
$m, real 2024-25	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
AER forecast	142.5	98.5	88.2	78.3	66.7	61.8	60.4	51.8
Property	48.9	28.6	24.7	19.3	45.1	33.9	19.1	34.0
Fleet	29.5	28.0	17.0	27.3	37.4	19.4	18.2	26.8
Tools and Equipment	16.2	15.1	6.8	7.1	11.6	5.2	4.9	5.9
Capitalised Leases	-	-	-	-	-	-	-	-

Table 45: Forecast other non-network capex ($m, real 2024-25)

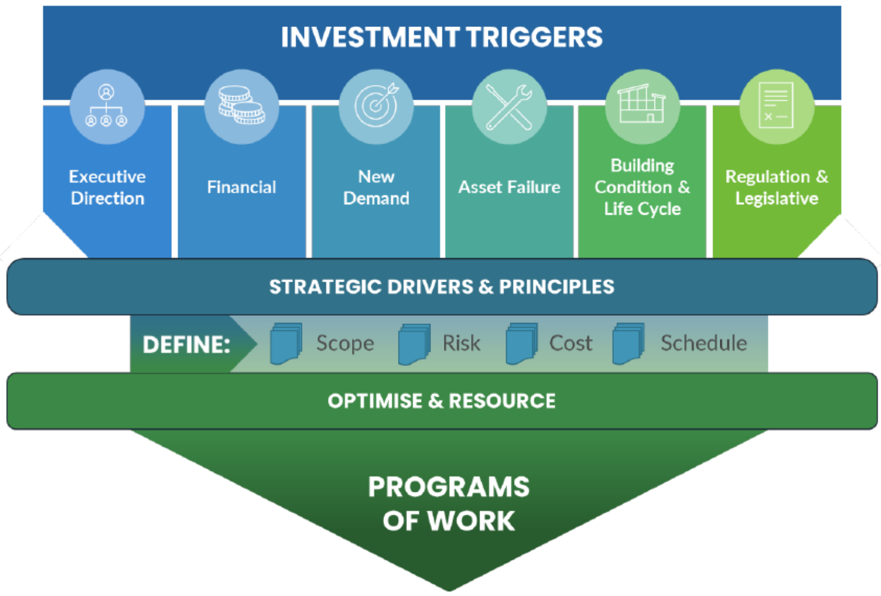
	Current Period		Future Period				
$m, real 2024-25	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
AER forecast	42.3	44.6	n/a	n/a	n/a	n/a	n/a
Property	26.3	28.6	31.9	26.0	31.2	35.3	33.0
Fleet	40.0	66.2	57.8	56.4	44.1	36.0	48.8
Tools and Equipment	5.0	6.2	6.7	6.3	6.4	6.2	6.0
Capitalised Leases	-	-	-	-	-	14.7	2.5

5.9.1 Our forecasting approach

5.9.1.1 Property

The general approach to forecasting investment in the non-network property portfolio is summarised in Figure 43.

Figure 43: Property capex – general forecasting approach



Major property projects represent individual investments and are forecast using a bottom-up approach, including business cases with detailed NPV options analysis. Other categories of property (including minor, base, residence and security) are generally forecast using a base-step-trend approach, based on historical expenditure.

Additional information can be found in our Non-Network Property Plan 2025-30 (Attachment 5.9.01).

5.9.1.2 Fleet

The network program of work and employee numbers are a key driver of fleet expenditure, directly influencing both the volume and type of vehicles required to support operational needs. The varied composition of our fleet reflects the need for our diversely skilled workforce to perform a variety of activities across a range of operating conditions. These fleet items are specified, selected and allocated based on the fit-for-purpose operational needs of the business.

For our planned replacement program, the optimal replacement criteria for each type of vehicle are selected to maximise the efficiency of the asset and to ensure both lifecycle cost management and operational flexibility.

Additional information can be found in our Non-Network Fleet Plan 2025-30 (Attachment 5.9.06).

5.9.1.3 Tools and equipment

The network program of work, additional fleet, and employee numbers are the key drivers of tools and equipment expenditure, directly influencing both the volume and type of equipment required to support operational needs. The forecast is based on the historical trend, with an uplift included for additional field employees and fleet.

Additional information can be found in our Non-Network Tools and Equipment Plan 2025-30 (Attachment 5.9.10).

5.9.2 Summary of proposed investments

Our proposed other non-network capex for the 2025-30 regulatory control period is outlined in Table 46.

Table 46: Property, fleet and tools capex for 2025-30, $m 2024-25

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Property	31.9	26.0	31.2	35.3	33.0	**157.4**
Fleet	57.8	56.4	44.1	36.0	48.8	**243.0**
Tools and Equipment	6.7	6.3	6.4	6.2	6.0	**31.7**
Capitalised leases	-	-	-	14.7	2.5	**17.3**
Total[1]	**96.4**	**88.6**	**81.7**	**92.2**	**90.4**	**449.4**

Note 1: Totals may not add due to rounding. Capex reported above represents gross capex. Any proposed sales are included in our disposals (see SCS PTRM (Attachment 8.03)).

5.9.2.1 Property

Our proposed non-network property capex for the 2025-30 regulatory control period is driven by several major projects required to address capacity constraints and condition-based assessments on our property assets. This includes:

- a new fit-for-purpose workshop at Banyo, primarily driven by growth at the site and the end of the current lease term
- a new site for a minor hub depot at an industrial site at Bundaberg (including the sale of the existing site), primarily driven by growth in the region and the upgrade in status from a regional hub to a minor hub
- a new site for a minor hub depot at an industrial site in Sarina (including the sale of the existing site), primarily driven by growth in employee numbers and building condition
- a redevelopment of the training facility in Townsville, primarily driven by growth in training requirements and building condition, and
- capex on our minor, base, security and residence programs in line with historical spend.

5.9.2.2 Fleet

Our proposed non-network fleet capex for the 2025-30 regulatory control period is driven by:

- our planned replacement program, including significant increases in the purchase price of vehicles
- the need to invest in an ageing fleet which could not be replaced due to market supply challenges in the current 2020-25 regulatory control period, and
- growth in the program of work and employee numbers driving increasing fleet requirements.

5.9.2.3 Tools and equipment

Our proposed non-network tools and equipment capex for the 2025-30 regulatory control period is consistent with our current spend, with a minor allowance for an increasing program of work.

5.9.2.4 Capitalised leases

Our proposed capitalised leases expenditure over the 2025-30 regulatory control period represents a new component of our capex, as these leases were treated as opex in the 2020-25 regulatory control period.

The previous accounting standard, AASB 117 *Leases,* was replaced by AASB 16 *Leases* on 1 July 2019. AASB 16 *Leases* introduces a new requirement for a lessee to recognise assets and liabilities for the rights and obligations created by leases. For additional information, see section 8.4.1.2. For regulatory reporting purposes, Ergon Energy Network will adopt this change from 1 July 2025.

The forecast represents the capitalisation of property leases for the existing office sites at Townsville and Cairns,[16] which have five-year lease extensions proposed in the 2025-30 regulatory control period.

[16] Although these offices are in the Energy Network distribution area, Energy Queensland considers that major office locations are Energy Queensland assets and the costs are subsequently shared across both DNSPs and the unregulated business based on a CAM allocation.

5.9.3 How this differs from our Draft Plan

The forecast capex included in our Regulatory Proposal differs to what was included in the Draft Plan, namely:

- property expenditure is 2.4 per cent lower than the forecast in the Draft Plan. This difference is primarily driven by more detailed project cost estimates being available. In addition, noting customers affordability concerns, we have reprioritised some of our major projects in the original forecast, and delayed those where it was possible to do so
- fleet expenditure is 5.4 per cent higher than the forecast in the Draft Plan. This difference is driven by several factors which have both increased and decreased the forecast, including more detailed unit rates being available, and a revision to the allocation rate between Ergon Energy Network and Energex. In addition, noting customers' affordability concerns, we have removed the additional capex relating to the transition of a small portion of the fleet to electric vehicles, and
- tools and equipment expenditure is 12.9 per cent higher than the forecast in the Draft Plan. This difference is primarily driven by a revision to the allocation rate between Ergon Energy Network and Energex.

Capitalised leases expenditure is in line with the Draft Plan forecast.

5.9.4 Delivering for our customers

As an enabler to business operational requirements, non-network assets are utilised by the business to undertake construction, maintenance and service activities and to enable support services to deliver core distribution business functions for our customers.

Our property portfolio supports regional Queensland communities by ensuring the infrastructure assets we own and operate support the business to deliver our customers' energy requirements now and into the future. These assets need to be positioned in the right locations with the right investment decisions to enable the safe and efficient operation of the distribution network.

In addition, our fleet asset management is designed to minimise the total asset lifecycle costs. We periodically review fleet operations, standards, market prices and existing commercial arrangements to ensure opportunities to derive cost savings from changes to our fleet are being identified and taken advantage of in a timely manner. It is important to note that an ageing fleet being off the road not only impacts operating costs, but also materially impacts the efficiency and productivity of teams delivering capital and operating works programs for our customers.

5.9.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Property		
Property Plan 2025-30	5.9.01	Ergon - 5.9.01 - Non-network Property Plan 2025-30 - January 2024 - Public Ergon – 5.9.01 - Non-network Property Plan 2025-30 - January 2024 - Confidential
Business Case – Banyo Workshop	5.9.02	Ergon - 5.9.02A - Business case Non-network Property - Banyo Workshop - January 2024 - Public Ergon - 5.9.02A - Business case Non-network Property - Banyo Workshop - January 2024 - Confidential Ergon - 5.9.02B - NPV Model Non-network Property - Banyo Workshop - January 2024 - Confidential
Business Case – Bundaberg Depot	5.9.03	Ergon - 5.9.03A - Business case Non-network Property - Bundaberg Depot - January 2024 - Public Ergon - 5.9.03A - Business case Non-network Property - Bundaberg Depot - January 2024 - Confidential Ergon - 5.9.03B - NPV Model Non-network Property - Bundaberg Depot - January 2024 - Confidential
Business Case – Sarina Depot	5.9.04	Ergon - 5.9.04A - Business case Non-network Property - Sarina Depot - January 2024 - Public Ergon - 5.9.04A - Business case Non-network Property - Sarina Depot - January 2024 - Confidential Ergon - 5.9.04B - NPV Model Non-network Property - Sarina Depot - January 2024 - Confidential
Business Case – Townsville Training	5.9.05	Ergon - 5.9.05A - Business case Non-network Property - Townsville Training - January 2024 - Public Ergon - 5.9.05A - Business case Non-network Property - Townsville Training - January 2024 - Confidential Ergon - 5.9.05B - NPV Model Non-network Property - Townsville Training - January 2024 - Confidential
Fleet		
Fleet Plan 2025-30	5.9.06	Ergon - 5.9.06 - Non-network Fleet Plan 2025-30 - January 2024 - Public
Business Case EWP Replacement	5.9.07	Ergon - 5.9.07A - Business Case Non-Network Fleet - EWP Replacement - January 2024 - Public Ergon - 5.9.07A - Business Case Non-Network Fleet - EWP Replacement - January 2024 - Confidential Ergon - 5.9.07B - NPV Model Non-Network Fleet - EWP Replacement - January 2024 - Confidential
Business Case Crane Borer Replacement	5.9.08	Ergon - 5.9.08A - Business Case Non-Network Fleet - Crane Borer Replacement - January 2024 - Public Ergon - 5.9.08A - Business Case Non-Network Fleet - Crane Borer Replacement - January 2024 - Confidential Ergon - 5.9.08B - NPV Model Non-Network Fleet - Crane Borer Replacement - January 2024 - Confidential
Fleet Replacement Model	5.9.09	Ergon - 5.9.09 - Non-network Fleet forecast replacement model - January 2024 – Confidential
Tools and Equipment		
Tools and Equipment Plan 2025-30	5.9.10	Ergon - 5.9.10 - Non-network Tools and Equipment Plan 2025-30 - January 2024 - Public

5.10 Capitalised overheads

Overheads are business support costs that we incur in delivering network services to customers. They typically comprise of:

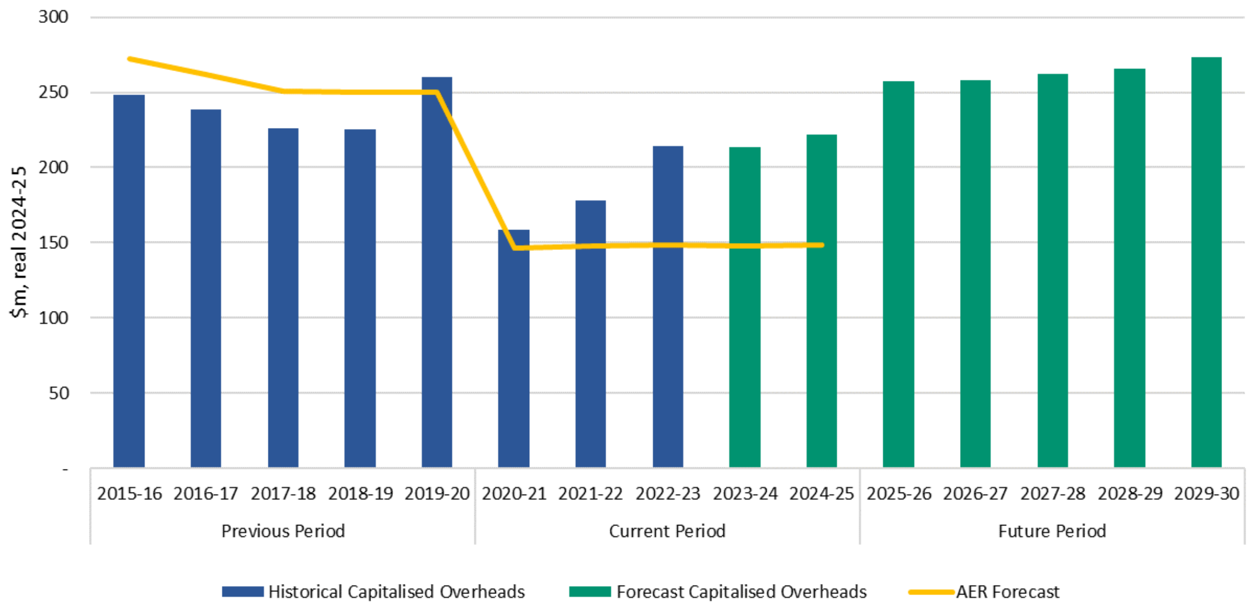
- **network overheads** - indirect costs incurred in activities such as network planning and project governance that are directly related to the network as well as indirect costs incurred to operate and maintain vehicles, and property occupancy, and
- **corporate overheads** – costs related to finance, regulation, human resources and non-network ICT costs.

In accordance with our CAM and capitalisation policies as well as accounting standards requirements, we capitalise some of our overheads (included in capex). We refer to these overheads as capitalised overheads. The balance of our overheads costs that are not capitalised are expensed (i.e. included in opex). In general, our network overheads are capitalised, while our corporate overheads are largely expensed, except for non-network ICT costs.

Our capitalised overheads forecast for the next regulatory control period is $1,316 million. While this represents an increase of 33 per cent compared to the current regulatory control period, we are working hard to constrain our overheads.

Our forecast overheads are at similar levels to our previous regulatory control period despite our much higher overall capex requirements. Ergon Energy Network is currently in a different phase of its investment cycle, with our current and forecast capex requirements significantly exceeding that of any other distributor in the NEM. The increase in overheads reflects this (refer to Figure 44). Our capitalised overheads forecast is based on our internal forecasts and includes a 1 per cent annual productivity factor, consistent with our Draft Plan.

Figure 44: Capitalised overheads between 2015 to 2030 ($m, real 2024-25)



The data supporting Figure 44 is provided in Table 47 and Table 48.

Table 47: Historical capitalised overheads ($m, real 2024-2025)

	Previous Period					Current Period		
$m, real 2024-25	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
AER forecast	272.6	261.5	250.6	249.9	249.9	146.5	147.5	148.3
Overheads	248.5	238.8	226.4	225.6	260.1	158.5	178.3	214.1

Table 48: Forecast capitalised overheads ($m, real 2024-2025)

	Current Period		Future Period				
$m, real 2024-25	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
AER forecast	147.9	148.7	n/a	n/a	n/a	n/a	n/a
Overheads	213.3	222.1	257.3	257.8	262.4	265.4	273.1

6.
Operating Expenditure

Key messages:

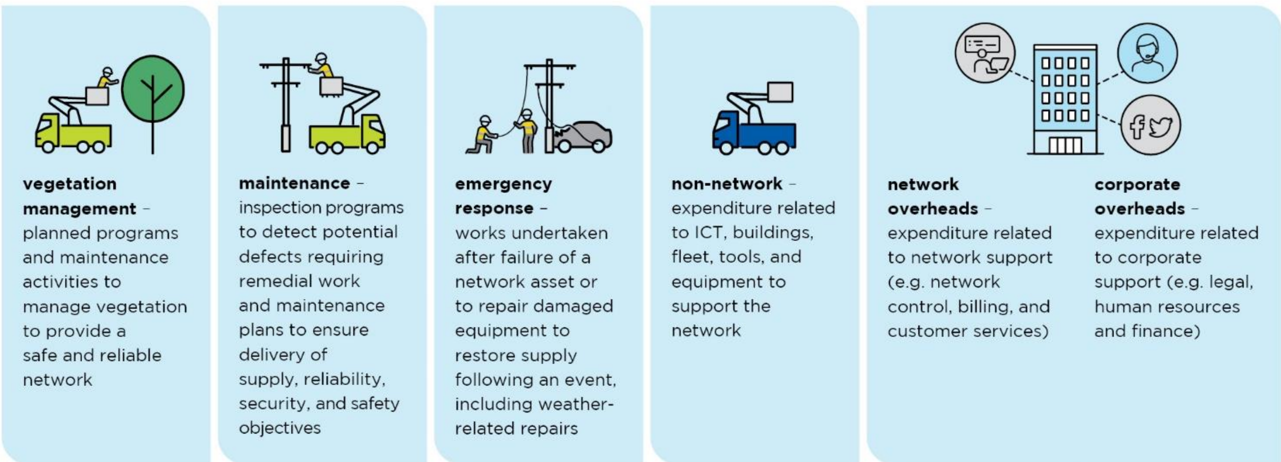
- Our customers expect Ergon Energy Network to continue to affordably deliver a safe, secure and reliable network.
- Our forecast opex to meet customers' expectations for the 2025-30 regulatory control period is $2,379 million. This represents an increase of 0.1 per cent relative to our actual opex and 3.9 per cent to the AER's forecast for the current regulatory control period, respectively.
- We have adopted the AER's preferred base-step-trend approach to developing our forecast opex, using 2023-24 as the base year.
- To address customers' affordability concerns, we have made an efficiency adjustment to the base year, applied a 1 per cent productivity factor and reduced our step changes. Together, these measures have reduced our forecast opex by 6.5 per cent relative to our Draft Plan.
- A step change has been proposed for acquisition, processing and use of smart metering data to provide greater visibility of our low voltage network, which will enable us to improve safety and reliability outcomes, enhance our ability to integrate more DER into the network and reduce our asset replacement costs.
- Our opex forecast is one of the building blocks that form part of our revenue requirement.

6.1 Overview

Opex refers to the non-capital expenses that we incur in operating and maintaining the distribution network for the benefit of our customers. It is a key building block of our annual revenue requirement (ARR), and costs are recovered on an annual basis.

Our opex is broken down into the high-level categories set out in Figure 45.

Figure 45: Opex categories



Customers have told us that, although affordability of electricity supply is their primary concern, they expect Ergon Energy Network to keep our network safe, reliable and secure and to keep the lights on for their homes and businesses. They rely on us to be vigilant with respect to the safety of our network and particularly value how we respond to severe weather events and natural disasters to ensure power supply is restored to communities as quickly as possible. Ergon Energy Network's opex is therefore focused on ensuring that we continue to operate and maintain our network to meet the everyday performance and service expectations of our customers and communities, in the most affordable way.

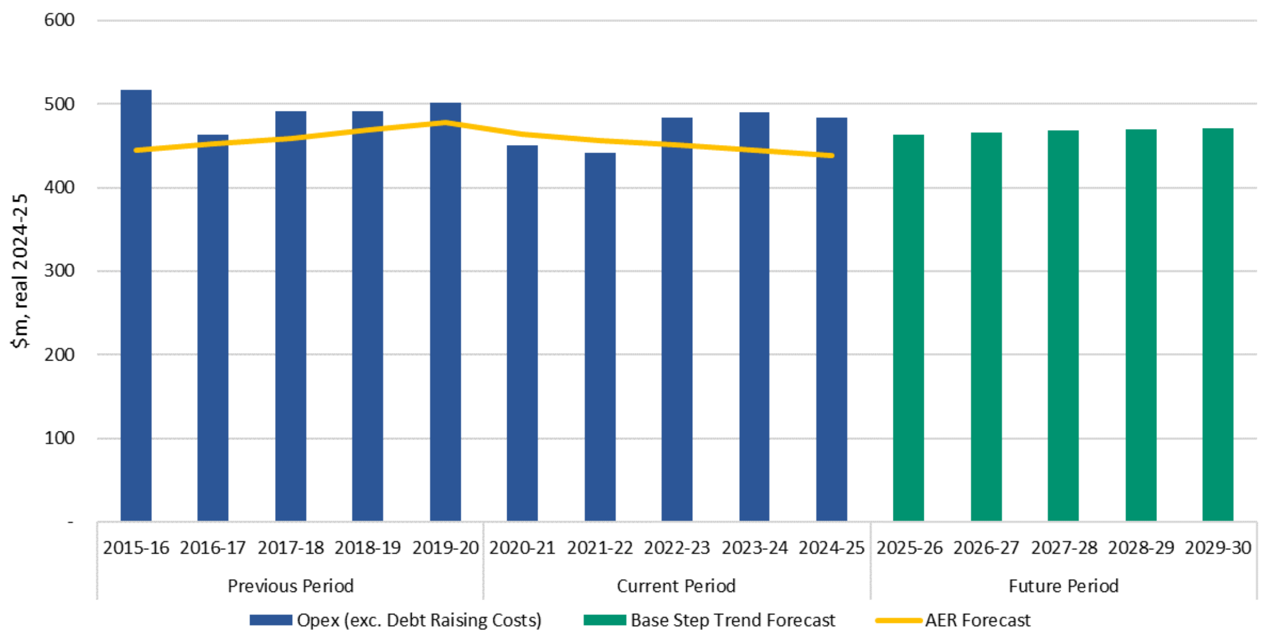
For the 2025-30 regulatory control period, we are forecasting opex of $2,379 million as set out in Table 49. This represents an increase of 0.1 per cent and 3.9 per cent relative to our actual opex and AER allowances, respectively, for the current regulatory control period. We consider this level of opex is required to carry out the activities outlined in Figure 45, to achieve the opex objectives listed in clause 6.5.6 of the NER. For additional information see Attachment 6.01.

Table 49: Forecast opex 2025-30 ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Opex (excl. debt raising costs)	462.7	465.2	467.7	469.1	471.3	**2,336.0**
Debt raising costs	8.1	8.4	8.6	8.9	9.1	**43.1**
Total opex[1]	**470.8**	**473.6**	**476.4**	**477.9**	**480.4**	**2,379.1**

Note 1: Totals may not add due to rounding.

Figure 46: Opex between 2015 to 2030 ($m, real 2024-25)



The data supporting Figure 46 is provided in Table 50 and Table 51.

Table 50: Historical opex ($m, real 2024-25)

	Previous Period					Current Period		
$m, real 2024-2025	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**
AER forecast[1]	444.1	451.7	459.2	468.7	477.6	463.4	456.8	451.0
Opex[1]	517.2	463.0	491.5	491.1	502.1	450.8	441.2	483.3

Note 1: excludes debt raising costs.

Table 51: Forecast opex ($m, real 2024-25)

	Current Period		Future Period				
$m, real 2024-25	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
AER forecast[1]	444.8	438.7	n/a	n/a	n/a	n/a	n/a
Opex[1]	490.2	484.0	462.7	465.2	467.7	469.1	471.3

Note 1: excludes debt raising costs.

The key drivers of our opex include:

- meeting the security, performance and reliability needs of customers
- inspecting and maintaining assets to ensure that they are operating safely and efficiently over their lifetimes
- meeting legislative requirements
- responding to storm and other severe weather events to restore supply
- meeting growth in our network as measured by the number of connected customers, line length and the increased maximum demand of our customers
- actively managing vegetation near our assets, and
- addressing ageing infrastructure and asset-related safety hazards.

Our opex takes into consideration the additional costs of operating in regional Queensland, including costs associated with travelling long distances, accessing remote and difficult to reach communities, additional wear and tear on our network assets and fleet vehicles, and the challenges of achieving operational efficiencies across such a dispersed area.

6.2 Key assumptions

Table 52 details the key assumptions underpinning our opex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6.1.2(6) of the NER, as discussed in section 12.8.1 of this Regulatory Proposal. A copy of the certification is provided in Attachment 12.04.

Table 52: Key assumptions – Opex

	Issue	Assumption
1	Structure and ownership	Our forecasts are based on our current company structure and ownership arrangements.
2	Legislative and regulatory obligations	Our forecasts are based on our current legislative and regulatory obligations and our Distribution Authority.
3	Service classification	We will apply the service classification set out in the AER's F&A.
4	Customer preferences and expectations	The preferences and expectations of our customers and stakeholders revealed through our stakeholder engagement program have been considered in developing our Regulatory Proposal.
5	Service outcomes	We will maintain, but not improve, our average system-wide service outcomes, consistent with clauses 6.5.6(a) and 6.5.7(a) of the NER.
6	Forecast capex and opex	Our capex and opex forecasts have been developed to meet the requirement to deliver safety, reliability and customer service outcomes.
7	Customer numbers	Our base case customer number forecast provides an appropriate approach for our connex forecast and the customer numbers component of our opex rate of change.
8	Cost allocation	Our CAM provides an appropriate basis for attributing and allocating costs to, and between, our distribution services.
9	Inflation	Our forecast inflation is reasonable and reflects the inflation-related costs that we will incur.
10	Opex base year	The financial year 2023-24 is an appropriate base year for our opex forecast and, subject to our proposed adjustments, is reasonably representative of our recurrent prudent and efficient future opex requirements.
11	Opex trend assumptions	Our forecast changes in input costs, output growth and productivity are reasonable and appropriately reflect the trend in our future opex, given our (adjusted) opex base year.

6.3 Our forecasting approach

Ergon Energy Network has applied a base-step-trend methodology to calculate the majority of our opex forecast. This approach is in line with the AER's *Expenditure Forecast Assessment Guideline* and is the same approach used to set the allowance for the current regulatory control period.

The process of forecasting opex involves five steps as summarised in Figure 47.

Figure 47: Approach to forecasting opex

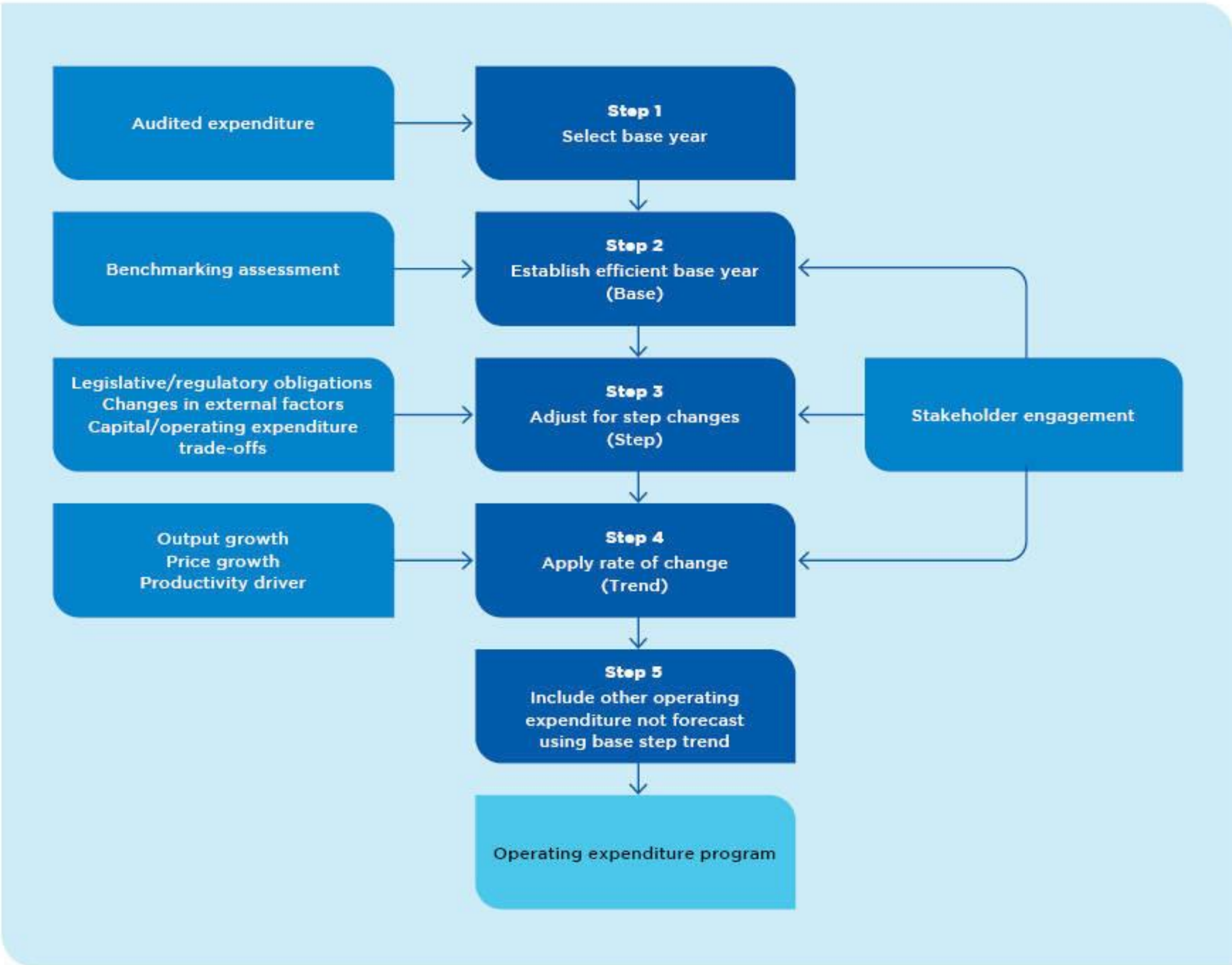


Table 53 outlines the approach that we have taken in preparing forecasts for the 2025-30 regulatory control period.

Table 53: Our approach to preparing our opex forecast for 2025 to 2030

Step	2025-30 period
Step 1 – Select base year	We select a base year that represents a realistic expectation of the efficient level of opex required to provide network services in the next regulatory control period. For the 2025-30 regulatory control period, we have selected a base year of 2023-24.
Step 2 – Establish efficient base	We test the base year for efficiency (using a benchmarking assessment) and make any other necessary adjustments. We have included an efficiency adjustment for the base year based on our assessment of the latest AER benchmarking models. Adjustments to the base year have also been made to remove costs such as the Electrical Safety Office levy (which will be treated as a jurisdictional scheme) and property leases (which will be treated as capex).
Step 3 – Adjust for step changes	We include step changes to account for events or obligations that will occur in the next regulatory control period which either increase or decrease opex relative to the base year. These step changes are first assessed against the AER's step change criteria. A business case is also prepared where necessary. In the 2025-30 regulatory control period a step change has been included for smart meter data, representing a new cost that will be incurred during the period (refer to Attachment 6.05).
Step 4 – Apply rate of change	We trend the base year forward over the next regulatory control period to reflect changes in: • outputs, to account for network growth based on forecast customer numbers, demand, and circuit length • prices, to account for real escalation in labour rates (internal and contractor) based on advice from a consultant with experience in this area, and • productivity, to account for improvements over the period - we have applied a rate of 1 per cent, which exceeds the AER's standard rate of 0.5 per cent.
Step 5 – Include other opex	We include category-specific forecasts which use alternative approaches to the base-step-trend, and debt raising costs which are forecast using the AER's benchmark method.

6.3.1 Efficiency of the base year

For the 2025-30 regulatory control period, we have selected a base year of 2023-24. We chose 2023-24 to be used as a base year because it:

- continues the well-accepted regulatory practice of using the most recent year for which audited data is available by the time of the final distribution determination, and
- represents a realistic expectation of the efficient and sustainable on-going opex that is required to provide SCS services over the 2025-30 regulatory control period.

We have estimated our 2023-24 opex for use in this Regulatory Proposal, as actual data is not yet available. We will update our base year opex forecast in our Revised Regulatory Proposal to reflect actual data.

The AER released its latest *Annual Benchmarking Report: Electricity distribution network service providers* in November 2023 (2023 *Annual Benchmarking Report*). This report indicated that:

- in the multilateral total factor productivity results, the productivity for Ergon Energy Network decreased in 2022 and we are now ranked sixth (out of 13 DNSPs)
- in the econometric model results (long sample), Ergon Energy Network is ranked ninth using the approach in previous reports and eleventh under the approach to address capitalisation differences, and
- in the econometric model results (short sample), Ergon Energy Network is ranked tenth using the approach in previous reports and eleventh under the approach to address capitalisation differences.

However, it is important to note that the multilateral total factor productivity and econometric results presented in the AER's *Annual Benchmarking Report* do not include the impact of all material operating environment factors. These are accounted for separately in the base year assessment analysis. In addition, while opex is largely recurrent, short-term fluctuations can increase opex and could have a negative influence on annual benchmarking scores as a result.

We have reviewed our revealed base year opex against the expected outcomes of the AER's most recent economic benchmarking models and analysis applied in recent determinations.

As a result of our assessment, we have included a 2.3 per cent efficiency adjustment to our base year opex. Further detail on how our base year opex compares to economic benchmarks is included in the *Frontier Economics – Opex benchmarking report* (Attachment 6.04).

6.3.2 Other base year adjustments

We have made other adjustments to our opex base year as follows:

- deducted $7.7 million in costs for the Electrical Safety Office levy (which will be treated as a jurisdictional scheme in 2025-30),[17] and
- deducted $5.9 million in costs relating to property leases (which will be treated as capex in 2025-30).[18]

The adjustments for efficiency and other items have been applied consistent with previous AER determinations and reduce our base year opex from $484 million to $459.3 million.

6.3.3 Step changes

The AER's *Better Resets Handbook* notes that step changes may arise from a change in regulatory obligations, a capex/opex substitution or a change driven by major external factor(s) outside the control of a business. For our Regulatory Proposal, Ergon Energy Network has identified and quantified one significant cost for the 2025-30 regulatory control period which will be treated as a step change. However, we are still assessing the potential costs relating to increased regulatory obligations for the inspection of private property poles. If required, this may be included as a second step change in our Revised Regulatory Proposal.

[17] The Electrical Safety Office levy has been reclassified as a Jurisdictional Scheme, effective 1 July 2025 and is therefore no longer funded through the opex allowance. Instead, the levy costs will be funded through Jurisdictional Scheme charges.

[18] The previous accounting standard, AASB 117 Leases, was replaced by AASB 16 Leases on 1 July 2019. AASB 16 Leases introduces a new requirement for a lessee to recognise assets and liabilities for the rights and obligations created by leases. For regulatory reporting purposes, Ergon Energy Network will adopt this change from 1 July 2025.

6.3.3.1 Description

The proposed step change for smart meter data relates to the acquisition, processing, and use of smart meter data.

6.3.3.2 Driver and benefits

This change is driven by major external factors. Both the Australian Energy Market Commission's (AEMC's) *Review of the Regulatory Framework for Metering Services* and the *Queensland Energy and Jobs Plan* have targeted 100 per cent smart meter penetration by 2030. The AEMC further recommended that basic power quality data should be provided free of charge to DNSPs, with advanced power quality data provided through a negotiated arrangement with metering providers.

Our existing visibility of power flows and other information on our low voltage networks is very limited. The rollout of smart meters across our network will provide us with the opportunity to actively monitor our low voltage network. The benefits include:

- **reliability** – improved reliability from identifying and responding more quickly for service line and distribution transformer failures
- **CECV** – better visibility allows us to set less conservative operating envelopes for export and will improve our ability to integrate more DER into our network
- **safety** – obtaining data will allow us to determine broken neutrals on our low voltage service lines, and
- **financial** – monitoring our low voltage service population will allow us to time our replacements more effectively, reducing replacement costs.

6.3.3.3 Preferred option

Our proposed step change includes:

- acquiring advanced (near real-time) power quality data for 25 per cent of the available smart meters, which is the critical mass of data required for a highly accurate real-time assessment of our low voltage network to enable the integration of DER and export at the most efficient level. This would provide us enough data to be able to respond quicker to network outages on distribution transformers and service lines
- acquiring basic power quality data for the remaining 75 per cent of smart meters for our overhead service lines only. This will enable us to detect emerging defects and failures on our service lines to prevent safety and reliability issues for our customers. This data is assumed to be free of charge under the AEMC's recommendation, and
- provision of a data platform to land and analyse the smart meter data that we acquire. This cost will be shared across Ergon Energy Network and Energex and has been assigned proportionally according to the number of smart meter points we expect in each network.

Table 54 summarises the costs we are forecasting for the 2025-30 regulatory control period associated with acquiring smart meter data.

Table 54: Forecast step changes for 2025-30 period

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Smart meter data	1.0	1.2	1.4	1.6	1.7	**6.8**

Note 1: Total may not add due to rounding.

It should be noted that access to basic power quality data is currently only a recommendation by the AEMC and has not been enacted in the NER. In proposing this step change, we are assuming that this recommendation will proceed unchanged, and that the definitions of 'basic' and 'advanced' power quality data are in line with our expectations. We may revisit this step change in our Revised Regulatory Proposal should the AEMC's recommendations change as they progress through to the NER.

6.3.3.4 Customer engagement

We discussed our approach to the acquisition of smart meter data with our RRG to guide the way we considered the benefits that would flow to customers from this investment. The RRG provided feedback that investment should be based on the highest cost-benefit option, without bias to technology or timing of costs. To this end, we have undertaken a cost-benefit analysis and sensitivity analysis to determine which of the options maximises the benefits to our customers and the community.

More information on our proposed step change can be found in our Smart Meter Data Acquisition Business Case (Attachment 6.05).

6.3.4 Rate of change

The efficient base year is trended forward over the regulatory control period to reflect changes in price, outputs and productivity.

6.3.4.1 Price growth

Our base year opex reflects the current prices of our cost inputs. The base-step-trend approach adjusts this base year opex to account for forecast real change in input costs over the 2025-30 regulatory control period. Our trend adjustments are based on forecasts prepared by Oxford Economics (Attachment 6.03). We note that the AER's preferred approach is to use the average of the Oxford Economics forecast with the forecast commissioned by the AER (expected to be undertaken by KPMG). As we do not have the KPMG forecast escalation rates for Queensland, we have used the national rate as a placeholder. The different forecast price growth rates are provided in Table 55.

Table 55: Forecast price growth 2025-30

	Future Period				
Per cent	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Real labour forecast – Oxford Economics	1.30%	1.18%	0.92%	1.22%	1.38%
Real labour forecast – KPMG National	0.90%	1.10%	1.10%	1.10%	1.10%
Average of real labour forecasts	1.10%	1.14%	1.01%	1.16%	1.24%
Superannuation guarantee	0.50%	0.00%	0.00%	0.00%	0.00%
Average plus superannuation guarantee	1.60%	1.14%	1.01%	1.16%	1.24%
Price growth (assuming 59.20% labour)	0.95%	0.68%	0.60%	0.69%	0.73%

6.3.4.2 Output growth

Our base year reflects our current outputs. The base-step-trend approach adjusts this base year opex to account for the forecast change in outputs over the 2025-30 regulatory control period. We have included an allowance for output growth consistent with the AER's standard approach.

We have applied the output change measures and respective weightings in the *Economic Insights Report* released with the AER's 2023 *Annual Benchmarking Report*. Our forecast output growth rates for 2025-30 regulatory control period are in Table 56.

Table 56: Forecast output growth 2025-30

	Future Period					
	Average weighting	2025-26	2026-27	2027-28	2028-29	2029-30
Customer numbers	45.48%	0.83%	0.84%	0.82%	0.77%	0.75%
Circuit length	14.87%	0.33%	0.33%	0.34%	0.33%	0.34%
Ratcheted maximum demand	39.65%	0.39%	0.99%	1.27%	0.44%	0.81%
Average output growth		0.58%	0.82%	0.92%	0.57%	0.71%

6.3.4.3 Productivity growth

Productivity improvements can result from technical change, efficiency, or economies of scale. Recognising that our opex has been increasing, we are committed to delivering productivity improvements in the 2025-30 regulatory control period. Given the affordability concerns raised by our customers and the expected material increases in our overall revenues in the 2025-30 regulatory control period, our Executive Management and Board have decided to apply a 1 per cent productivity rate to our forecast opex. This exceeds the AER's standard rate of 0.5 per cent.

6.3.5 Specific or category forecasts

Debt raising costs are the transaction costs incurred in raising debt, including the costs of maintaining an investment credit rating needed to issue this debt. We estimated the debt raising costs using the AER's preferred 'benchmark' methodology. We have estimated a benchmark unit rate of 8.4 basis points per annum and applied it to our forecast RAB. The calculation of our debt raising costs is set out in the Post Tax Revenue Model (PTRM) (Attachment 8.03).

6.4 Summary of our proposed operating expenditure for 2025-30

In line with the base-step-trend forecast approach, the total 2025-30 forecast opex is provided in Table 57.

Table 57: Opex forecast for 2025 to 2030

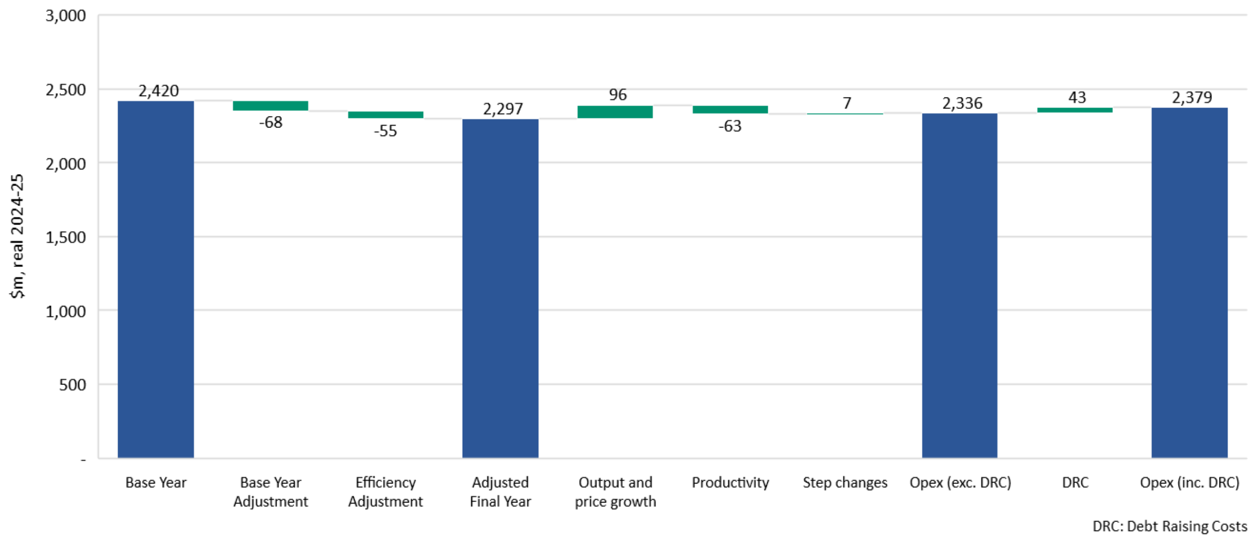
	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Base opex	484.0	484.0	484.0	484.0	484.0	**2,419.9**
Base year adjustments	-24.6	-24.6	-24.6	-24.6	-24.6	**-123.2**
Price growth	4.3	7.2	9.7	12.5	15.4	**49.1**
Output growth	2.6	6.2	10.2	12.4	15.3	**46.7**
Productivity growth	-4.5	-8.8	-12.9	-16.7	-20.4	**-63.3**
Step changes	1.0	1.2	1.4	1.6	1.7	**6.8**
Debt raising costs	8.1	8.4	8.6	8.9	9.1	**43.1**
Total[1]	**470.8**	**473.6**	**476.4**	**477.9**	**480.4**	**2,379.1**

Note 1: Totals may not add due to rounding.

As illustrated in Figure 48, this forecast includes:

- an estimated $2,420 million in base year opex costs
- an estimated $123 million reduction to the base year
- an estimated $96 million increase in expenditure for output and price growth
- an estimated $63 million reduction in expenditure for productivity improvements
- an estimated $7 million in additional expenditure for step changes, and
- an estimated $43 million in debt raising costs.

Figure 48: Breakdown of our opex forecast for 2025 to 2030 ($m, real 2024-25)



6.5 How this differs from our Draft Plan

In our Draft Plan, we proposed forecast opex of $2,454 million. In response, customers were generally supportive of our proposal to apply a 1 per cent productivity factor as a way to address their affordability concerns. For the Regulatory Proposal, we have retained the 1 per cent productivity factor and have further reduced our forecast opex by 3.1 per cent through:

- the inclusion of an efficiency adjustment based on an assessment of our 2023-24 base year. While we consider that an efficiency adjustment is not required in light of the material concerns that we have with the AER's benchmarking model, we have incorporated the efficiency adjustment to further address affordability concerns. Applying the efficiency adjustment lowers our opex by $55 million over five years
- removal of the cyber security ($5 million) and insurance premium ($4 million) step changes. We considered that these step changes were immaterial and that their removal would further improve affordability
- a revision of the smart meter data step change from $37 million to $7 million following the AEMC's review, and
- other minor changes to output and price growth assumptions.

6.6 Delivering for our customers

From the engagement we have undertaken to date, customers have told us that:

- affordability is their primary concern
- if the network is not appropriately managed it presents a risk to our communities and employees and customers expect Ergon Energy Network to be vigilant, and to always make safety our priority
- reliability is a key priority and we have the balance between reliability and cost about right
- Queenslanders know that storms, cyclones, bushfires, floods and other disasters are beyond anyone's control, and our response to recent natural disaster events continues to show we respond well when these events occur and that our contribution is important to communities in getting them back up and running quickly, and
- they are generally supportive of the 1 per cent productivity factor being applied.

We consider that the measures we have made to reduce our forecast opex will help to address the affordability concerns raised by customers. The reductions will be a significant challenge for our business as the costs of managing our network continue to rise. However, we are committed to continuing to deliver a safe, secure and reliable network in the 2025-30 regulatory control period.

6.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Addressing Capex objectives, criteria and factors	6.01	Ergon – 6.01 – Addressing Capex objectives, criteria and factors – January 2024 - public
Ergon SCS Opex Model	6.02	Ergon - 6.02 - Model - SCS AER Opex - January 2024 - public
Input Cost Escalation Forecasts to 2029/20	6.03	Ergon – 6.03 – Oxford Economics Australia – Input Cost Escalation Forecasts to 2029/20 – September 2023 - public
Frontier Economics – Opex Benchmarking	6.04	Ergon - 6.04 - Frontier Economics - Opex benchmarking report - January 2024 - public
Smart Meter Data Acquisition Business Case	6.05	Ergon - 6.05A - Business Case - Smart Meter Data Acquisition - January 2024 - public Ergon - 6.05A - Business Case - Smart Meter Data Acquisition - January 2024 - confidential Ergon - 6.05B – NPV Model - Smart Meter Data Acquisition - January 2024 - confidential

7.
Incentive Schemes

Key messages:

- We continue to support the application of incentive schemes, the purpose of which is to encourage us to be more efficient, maintain or improve our service performance and pursue alternative non-network options.
- We propose that current incentive schemes - STPIS, EBSS, CESS, DMIA and DMIAM – should continue to apply to Ergon Energy Network in the 2025-30 regulatory control period.
- While we support the ESIS, we do not have robust data that would allow us to design and consult on the scheme with customers, and propose that it does not apply in the next regulatory control period.
- Based on customer feedback that we should not be incentivised to provide good customer service, we propose that the CSIS should not apply.
- Given our customers' strong views that we should not be rewarded for good customer service, we also propose that the customer service component (telephone answering) of STPIS should not apply. We further propose that the overall revenue at risk cap should be reduced from 2 per cent to 1.8 per cent to account for the removal of the customer service component.

7.1 Overview

Customer feedback demonstrates that our customers are concerned about the cost of their electricity supply and that they expect us to maintain our service and performance levels without spending any more than is necessary.

The NER provide for a range of incentive schemes designed to enhance the incentive-based regulatory framework applied by the AER. These schemes incentivise networks like Ergon Energy Network to run efficient businesses so that customers pay no more than is necessary for the services they require and ensure that the right levels of service are delivered to customers. As such, we continue to support the application of incentive schemes.

On 3 July 2023, the AER published the Final F&A for the 2025-30 regulatory control period, setting out, amongst other matters, the application of incentive schemes. In accordance with the NER, our Regulatory Proposal must include our proposed application of the incentive schemes specified in the F&A. Table 58 summarises each of the incentive schemes specified in the F&A and whether we propose that the scheme should apply in the 2025-30 regulatory control period.

Table 58: Application of incentive schemes

Incentive Scheme	Description	Current period	Next period
Service Target Performance Incentive Scheme (STPIS)	The STPIS incentivises us to maintain or improve service performance	✓	✓
Efficiency Benefit Sharing Scheme (EBSS)	The EBSS incentivises us to undertake efficient opex	✓	✓
Capital Expenditure Sharing Scheme (CESS)	The CESS incentivises us to undertake efficient capex	✓	✓
Demand Management Innovation Allowance Mechanism (DMIAM)	The DMIAM provides research and development funding for innovative demand management solutions	✓	✓
Demand Management Incentive Scheme (DMIS)	The DMIS incentivises us to undertake efficient demand management activities	✓	✓
Customer Service Incentive Scheme (CSIS)	The CSIS incentivises us to improve customer service performance	×	×
Export Service Incentive Scheme (ESIS)	The ESIS incentivises us to improve export service performance	×	×

The incentive schemes that we are proposing should apply to us in the 2025-30 regulatory control period are consistent with those set out in our Draft Plan. That is, our Draft Plan proposed to continue with current incentive schemes (STPIS, EBSS, CESS, DMIA and DMIAM) and not apply the new CSIS and ESIS.

However, following feedback on our Draft Plan, we have changed our position on the application of the STPIS customer service component (telephone answering). Feedback on the Draft Plan mainly related to our proposed position to not apply the new CSIS and continue with the customer service component of the STPIS (telephone answering). The overwhelming sentiment expressed by customers was that customer service should not be incentivised for our business. Therefore, this Regulatory Proposal proposes to not apply both the CSIS and customer service component of the STPIS (telephone answering) in the next regulatory control period.

The following sections set out our proposal on each incentive scheme.

7.2 Capital Expenditure Sharing Scheme

The CESS incentivises us to undertake efficient capex over the regulatory control period by providing financial rewards and penalties for efficiency gains and losses on capex, respectively. Efficiency gains and losses are estimated as differences between the AER's capex allowances and actual capex. We share the efficiency gains and losses with customers.

7.2.1 Application of the CESS in the current period

The CESS, as set out in version 1 of the AER's *Capital Expenditure Incentive Guideline for Electricity Network Service Providers* (the *Capex Incentive Guideline*) applies to us in the current regulatory control period. A symmetrical 30 per cent sharing ratio applies to overspends and underspends of capex. That is, if we underspend, we retain 30 per cent and customers receive 70 per cent of the benefit of underspending. Likewise, if we overspend, we incur 30 per cent and customers incur 70 per cent of the cost of overspending.

Table 59 summarises our proposed CESS revenue adjustments for the 2025-30 regulatory control period, i.e. the outcomes from the application of the scheme in the current period. The detailed calculations are provided in the CESS models provided as Attachment 7.02 and Attachment RIN.04. The CESS revenue adjustments comprise:

- **a final year true-up of the CESS calculations for the 2019-20 year** - the CESS outcomes for the 2015-20 regulatory control period applied in the 2020-25 distribution determination included forecast capex for 2019-20 that is trued-up in the 2025-30 determination. Our actual capex for the 2019-20 year exceeded our indicative forecast, therefore we incur an additional CESS penalty of $88.6 million, and
- **the CESS outcomes from the current 2020-25 determination** - we are forecasting to overspend the AER's allowances over the current regulatory control period. The NPV of the overspend is $1,923.9 million and results in penalties of $625.9 million.

Table 59: Ergon Energy Network's CESS carryovers

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
CESS carryovers for the current regulatory control period	-125.2	-125.2	-125.2	-125.2	-125.2	**-625.9**
CESS true-up for 2019-20	-17.7	-17.7	-17.7	-17.7	-17.7	**-88.6**
Total CESS penalties[1]	**-142.9**	**-142.9**	**-142.9**	**-142.9**	**-142.9**	**-714.4**

Note 1: Negative number implies a penalty and positive number a reward from the preceding period. Totals may not add due to rounding.

The CESS stipulates that the AER may adjust the CESS carryovers for deferral of capex. Over the 2020-25 regulatory control period, we did not defer any material capex and underspend. Therefore the CESS calculations do not include any deferral of capex.

7.2.2 Ex post capex exclusions from the regulatory asset base

In accordance with the NER, our actual capex is subject to an ex post prudency and efficiency assessment by the AER when rolling forward the RAB. The NER further states that the AER may adjust past capex where a distributor has, amongst other things, overspent the AER's capex forecasts. The CESS provides that where capex is adjusted and excluded from the RAB, the CESS penalties are adjusted to ensure that a network does not bear a penalty that exceeds 100 per cent of the excluded capex.

For our 2025-30 distribution determination, the relevant period for the AER's ex post assessment is the period from 2018-19 to 2022-23, i.e. the last two years of the previous regulatory control period and the first three years of the current regulatory control period. Over this period, we overspent the AER's capex allowances by 42.8 per cent as shown in Table 60.

As such, we acknowledge that the overspend will be subject to a detailed ex post review by the AER.

Table 60: Ex post review period capex

$m, real 2024-25	AER Forecast 2018-19 to 2022-23	Actual Capex 2018-19 to 2022-23	Variance from Forecast[1]
Augmentation	400.2	269.2	32.7%
Connections (net)	270.7	314.9	-16.3%
Asset replacement	989.6	2,180.6	-120.4%
Non-network			
ICT	132.7	246.3	-85.5%
Property	99.8	151.5	-51.8%
Fleet	185.6	129.1	30.4%
Other non-network	33.6	34.7	-3.2%
Capitalised overheads	942.1	1,036.5	-10.0%
Total Net Capex[2]	**3,054.2**	**4,362.7**	**-42.8%**

Notes:
1.Positive value indicates we spent less than the forecast. Negative value indicates an overspend against forecast.
2. Net capex in this table does not account for asset disposals. Totals may not add due to rounding.

In our view, we consider that the overspend was prudent and efficient and therefore our actual capex over this period can be rolled into the RAB without adjustment. However, as we indicated in our Draft Plan, we are seeking to exclude from the RAB and self-fund the ICT overspend over the ex post review period. The ICT overspend over the ex post review period was incurred during the first three years of the current regulatory control period. Therefore, to simplify the modelling we have excluded the ICT overspend from 2020-21 to 2022-23.

7.2.3 Application of the CESS in the 2025-30 regulatory control period

In April 2023, the AER published its *Final decision - Review of incentive schemes for networks*. The final decision amended the *Capex Incentive Guideline* to vary the CESS including:

- applying a bright-line tiered sharing arrangement with a 30 per cent sharing ratio for any underspend up to 10 per cent of capex, a 20 per cent ratio for any underspend over 10 per cent and a 30 per cent sharing ratio for any overspend, and
- requiring network service providers to provide further information to better and transparently explain the reasons for differences between our expenditure forecasts and the actual capex incurred.

In the F&A, the AER proposed to apply version 2 of the CESS in the 2025-30 regulatory control period. We support the AER's position.

7.3 Efficiency Benefit Sharing Scheme

The EBSS incentivises us to continuously pursue opex efficiency improvements and share these with customers. The EBSS is intrinsically linked to the revealed cost (or base-step-trend) forecasting approach for opex – where forecast opex is based on actual opex incurred in a recent year (the base year). The EBSS addresses two potential incentive problems arising from this forecasting approach, being the incentive to increase opex in the base year or defer efficiency improvement until after the base year. The use of the revealed cost forecasting approach combined with the EBSS results in us earning the same reward and penalty in each year of the regulatory control period.

With the EBSS being linked to the revealed cost forecasting approach, the AER's F&A indicated that the application of the EBSS will occur if the opex forecasts are based on our revealed costs.

7.3.1 Application of the EBSS in the current period

Version 2 of the EBSS applies to us in the current regulatory control period. Our opex requirements have increased in the current period and we are currently forecasting to overspend our opex allowances. As a result, we are forecasting significant negative EBSS carryovers (i.e. penalties) as set out in Table 61. Attachment RIN.03 provides the calculations.

Table 61: Ergon Energy Network's EBSS calculation

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Forecast EBSS penalties	-50.1	-61.5	-66.5	-21.0	0.0	**-199.0**

Note 1: Total may not add due to rounding.

7.3.2 Application of the EBSS in the 2025-30 regulatory control period

We propose that version 2 of the EBSS should continue to apply in the next regulatory control period. As previously stated, the F&A indicates that the AER's decision on the application of the EBSS is conditional on the application of the revealed cost forecasting approach. While we have made some efficiency adjustments to our base year and acknowledge that these distort the sharing of efficiency gains and losses, we do not consider that the efficiency adjustments are material to the extent that we are not relying on our revealed costs and that the EBSS should not apply in the next regulatory control period.

Furthermore, in accordance with version 2 of the EBSS, we support the application of adjustments to forecast and actual opex when calculating EBSS carryovers during the 2025-30 regulatory control period, namely adjustments for:

- approved pass through amounts or opex for contingent projects
- movements in provisions
- capitalisation policy changes
- categories of opex not forecast using a single-year revealed cost approach for the regulatory control period, including debt raising costs and DMIAM, and
- inflation.

7.4 Service Target Performance Incentive Scheme

The STPIS incentivises us to maintain and improve service performance where customers are willing to pay for the improvements. The scheme balances the incentives provided under the current regulatory framework to reduce expenditure with the need to maintain and improve service performance.

7.4.1 Application of the STPIS in the current period

In the current regulatory control period, version 2.0 of STPIS (published in November 2018), applies to Ergon Energy Network. Table 62 outlines the specific aspects of the STPIS that currently apply to us.

Table 62: Application of STPIS in the current period

Matter	2020-25 Determination
Revenue at risk	±2 per cent
Segmenting of network	Urban, short rural and long rural
Applicable parameters for the s-factor	Reliability of supply: system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) Customer service: telephone answering
Performance targets	Based on the average performance over the past five regulatory years
Criteria for excluding certain events from s-factor calculations	Applied the methodology indicated in version 2.0 including the 2.5 beta method for calculating major event days
Incentive rates	Applied the methodology indicated in the national STPIS and the values of customer reliability set by the AER
Guaranteed service level component	Not applied (a jurisdictional guaranteed service level scheme applies)

7.4.2 Application of the STPIS in the 2025-30 period

We support the F&A position to continue to apply version 2.0 of the STPIS in the 2025-30 regulatory control period.

For the 2025-30 regulatory control period, we propose to continue with the current arrangements as set out in Table 62, with two related exceptions. We propose that the customer service component of the STPIS (telephone answering) should not apply. With the proposed removal of the customer service component of the STPIS, we also propose that the overall revenue at risk cap be reduced to 1.8 per cent from the current 2 per cent. This is because a 0.2 per cent revenue at risk cap currently applies to the customer service component.

The proposed removal of the customer service component is an outcome of our customer engagement in developing our 2025-30 Regulatory Proposal. As part of this process, we consulted with our customers on the application of a new CSIS to possibly replace the current STPIS customer service component. In response there was overwhelming feedback that although good customer service is highly valued, we should not be incentivised for this and therefore a CSIS should not apply. Our customers indicated that good customer service should be a given.

Considering this feedback, our Draft Plan proposed that a CSIS would not apply and the customer service component of the STPIS (telephone answering) would be retained. We received further feedback that, given our customers' strong views about us not being rewarded for good customer service, we similarly should not retain the STPIS customer service component in the next period. This was also a view expressed by our RRG.

7.4.2.1 Proposed performance targets and incentive rates

Reliability of Supply

Table 63 sets out our proposed targets and incentive rates for the 2025-30 regulatory control period. The STPIS model (Attachment 7.01) provides the detailed calculations. Our proposed targets are based on our average performance over the past five regulatory years. For the purposes of this Regulatory Proposal, we have used the five years from 2018-19 to 2022-23. We will update the targets in our Revised Regulatory Proposal to reflect the five-year period from 2019-20 to 2023-24. Also, consistent with the STPIS, we propose to modify our average performance over the past five years as outlined below to account for the years where our actual performance exceeded the revenue at risk cap.

Our proposed incentive rates are calculated in accordance with clause 3.2.2 of the STPIS and the formulae in Appendix B of the STPIS. Our key assumptions include:

- **Value of Customer Reliability (VCR)** – we based the VCR values on the AER's 2019 VCR Study (updated for inflation), noting that the AER is expected to review its VCR methodology by 31 December 2024, and we anticipate that the final incentive rates will reflect the updated VCR values
- **weighting for unplanned SAIDI and unplanned SAIFI** - we have adopted the weightings set out in the STPIS of approximately 60:40, and
- **expected average annual energy consumption by network type for the 2025-30 regulatory control period** - we currently do not develop energy consumption forecasts by feeder type and have therefore applied the average consumption ratios from the past five years to our overall forecast energy consumption data.

Table 63: Ergon Energy Network proposed targets

Proposed targets	Performance target	Incentive rate
Unplanned SAIDI		
Urban	118.469	0.01910
Short rural	283.835	0.02473
Long rural	773.349	0.00501
Unplanned SAIFI		
Urban	1.217	1.23976
Short rural	2.470	1.89445
Long rural	4.714	0.54760

Funded reliability improvements

We do not propose to modify the average performance to account for proposed reliability performance improvement programs.

While we have some investments for which reliability is the identified need for the investment, these programs are not aimed at improving our overall reliability measures. Rather, they are targeted at maintaining our existing levels of service for customers, and are in response to the changing nature of our network, such as an increased number of customers per feeder and increased network utilisation.

Our Worst Performing Feeder investment program is the result of a regulatory obligation in our Distribution Authority. The number of feeders targeted through this program are minimal, and while the improvements are important for the affected customers, at a network level these improvements are not significant enough to make a material impact on our overall network reliability performance.

7.5 Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

The DMIS incentivises us to undertake efficient expenditure on relevant non-network options relating to demand management. The DMIAM provides funding for research and development in demand management projects that have the potential to reduce long-term network costs.

The DMIS and DMIAM currently apply to us and we support the F&A position to continue to apply these schemes in the 2025-30 regulatory control period. Table 64 sets out our proposed DMIAM allowance for the 2025-30 regulatory control period. We expect to use this funding to explore opportunities associated with customer energy resources and evolving the capabilities and services required as we transition to a smart grid. Possible areas of interest that we could explore using DMIAM funding include:

- customer experience, customer and network value propositions associated with dynamic connections and dynamic operating envelopes
- electric vehicle charging
- SAPS customer pilots and microgrids
- optimising customer energy resources in fringe-of-grid areas
- access to flexible and efficient energy use by vulnerable customers
- electrification – opportunities for efficiency and demand flexibility
- tariff trials, and
- community batteries.

Importantly, under the DMIAM, any allowance that we do not use will be returned to customers in the 2030-35 regulatory control period.

Table 64: Ergon Energy Network's DMIAM allowance

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
DMIAM	1.5	1.5	1.6	1.6	1.6	**7.8**

Note 1: Total may not add due to rounding.

7.6 Export Service Incentive Scheme

The ESIS allows DNSPs to propose bespoke incentives related to export services based on their network circumstances, customer preferences and evidence-based performance data. The AER can set targets for export services and require distributors to report on performance against the targets, with financial rewards or penalties applying to reported performance (similar to the STPIS). The ESIS is a new scheme that was recently introduced in July 2023 by the AER.

While we support the introduction of this new scheme, we do not propose that the scheme should apply in the 2025-30 regulatory control period. We consider that we currently do not have robust data that would allow us to design and consult on the scheme with customers prior to the commencement of the 2025-30 regulatory control period.

7.7 Customer Service Incentive Scheme

The CSIS is a new incentive scheme introduced by the AER in July 2020 to encourage distributors to engage with customers, identify services that customers want to improve, and set targets and incentives to improve those services.

It is principles-based which means that we develop our own CSIS measures and approaches in collaboration with our customers. The CSIS was introduced to replace the current telephone answering measure in the STPIS with measures that customers value more highly. The application of the CSIS is not mandatory and will only apply if it is considered necessary or appropriate by our customers.

7.7.1 Customer engagement outcomes

To determine if the CSIS should apply to Ergon Energy Network as an additional incentive scheme in the next regulatory control period, we engaged with our residential and small business customers through the two-step Voice of the Customer Panel process.

In the first phase of the process, the Pre-Voice of the Customer Panel – Customer Consultation (or 'perspectives gathering') phase, we sought insights on the lived experiences of the 'quiet voices' and 'future voices' from our customer base. During this process, we presented information on the new CSIS, and customers were asked about their level of comfort with the scheme.

In response, the overwhelming sentiment was that good customer service should be part of every business and it was expected that Ergon Energy Network would provide this. While 22 per cent said they 'liked it' or 'loved it' and 30 per cent of customers said they could 'live with it', 48 per cent of participants 'lamented' or 'loathed' the idea of a reward scheme to support better customer service.

In the second phase of the process, the Voice of the Customer Panel - Customer Collaboration phase, the panel delivered a set of recommendations in relation to customer service. We received the Panel's recommendations on 26 August 2023, which included that the CSIS should not apply to Ergon Energy Network.

After reviewing the insights from the Voice of the Customer Panel process, our Draft Plan tested the position of not applying a CSIS in the 2025-30 regulatory control period. Customer feedback in response to the Draft Plan was consistent with that from the Voice of the Customer Panel process.

7.7.2 Our proposed position

Consistent with the feedback we have received from customers, we propose that the CSIS should not apply in the next regulatory control period.

Notwithstanding, given the overwhelming feedback from customers about the importance of excellent customer service, we commit to work with our customers and stakeholders to develop agreed customer service performance reporting throughout the period.

7.8 How this differs from our Draft Plan

In our Draft Plan we proposed that, for the 2025-30 regulatory control period:

- all existing incentive schemes should continue to apply, including the STPIS telephone answering measure
- the ESIS should not apply, given the unavailability of robust data, and
- the CSIS should not apply, based on early customer feedback obtained through the perspectives gathering phase of our engagement and the recommendations of the Voice of the Customer Panel.

The difference between the draft positions set out in the Draft Plan and this Regulatory Proposal is that, for reasons discussed in section 7.4.2 above, we propose that the STPIS telephone answering measure should not apply in the next regulatory control period.

7.9 Delivering for our customers

The AER's incentive schemes are designed to improve network efficiency and performance levels and reduce costs for customers. The continued application of these schemes will deliver benefits for customers in the long-term and is in keeping with customers' expectations that we should maintain our service and performance levels while spending no more than necessary for the services they value.

Despite customer feedback that the CSIS and STPIS telephone answering measure should not apply, our ongoing commitment to excellent customer service will ensure that current service levels are maintained or improved.

7.10 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Model - STPIS Targets and Incentive Rates	7.01	Ergon - 7.01 - Model STPIS Targets and Incentive Rates - January 2024 - public
Model - SCS CESS True-Up Model	7.02	Ergon - 7.02 - Model SCS CESS True-Up - January 2024 - public
Model - SCS EBSS Model	RIN.03	Ergon - RIN.03 - Model SCS EBSS - January 2024 – public
Model - SCS CESS Model	RIN.04	Ergon - RIN.04 - Model SCS CESS - January 2024 - public

8.
Annual Revenue Requirement

Key messages:

- We have heard from customers how important it is to balance the need to invest in our network to provide safe and reliable supply with efficiently delivering electricity services in the most affordable way.
- We propose that the total revenue we require to continue to build and maintain a safe and reliable network for our customers is $7,819 million for the 2025-30 regulatory control period. This represents an increase of 15 per cent.
- As a distribution business we are capital-intensive, which means that a large part of our forecast revenue is driven by uncontrollable factors, such as interest rates and inflation.
- The revenue increase is offset by adjustments due to anticipated penalties under the AER's capex and opex incentive schemes and business initiatives to address customers' affordability concerns.
- We propose to evenly smooth the revenue across the regulatory control period. This proposed approach is overwhelmingly supported by customers.
- We estimate that network charges will increase by an average of $66 or 6.0 per cent annually for residential customers, $146 or 6.8 per cent annually for small business customers, and $4,342 or 7.1 per cent for large customers connected at low voltage.

8.1 Overview

We have heard from our customers how important it is that we balance the need to invest in our network to provide safe and reliable supply with efficiently delivering electricity services in the most affordable way. This is a difficult challenge as our costs are increasing as we, like many of our customers, feel the impact of inflation on the costs of materials and other inputs.

As a regulated business, the AER will determine the amount we can recover from customers using a 'building block' approach to set our revenue. We believe that we have determined a prudent level of investment for our network considering the age of our assets, the growing two-way flow of electricity on our network, and the need to adapt to an increasingly digitalised and inter-connected electricity market.

We propose that the total revenue we require to continue to build and maintain a safe and reliable network for our customers is $7,819 million for the 2025-30 regulatory control period. This represents an increase of 15 per cent, in real terms, relative to the current regulatory control period and is the first time that we are forecasting revenues to increase since our first distribution determination (for the 2010-15 regulatory control period) under the AER.

We estimate that total annual network charges (inclusive of transmission charges and jurisdictional schemes) will increase, in nominal terms, by an average of $66 or 6.0 per cent annually for residential customers, $146 or 6.8 per cent annually for small business customers, and $4,342 or 7.1 per cent annually for a large business connected on the low voltage network.[19]

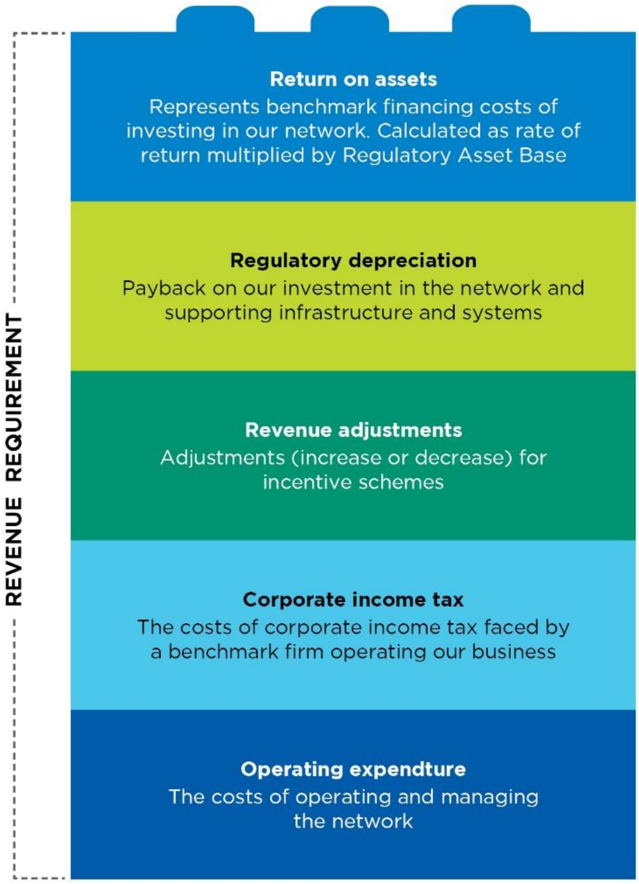
[19] The price impacts factor in transmission charges from Powerlink that are forecast to increase by inflation and the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. For forecast inflation, we have used a forecast of 2.80 per cent based on the AER's methodology set out in the PTRM (Attachment 8.03).

8.2 Our proposed annual revenue requirement

The ARR (or unsmoothed revenue) is the sum of the forecast efficient costs that Ergon Energy Network incurs each year in providing SCS to our customers. The ARR is calculated using a building block methodology outlined in Figure 49.

Since the ARRs can be lumpy and fluctuate materially from year-to-year, they are smoothed across the regulatory control period to determine the expected revenue (or 'smoothed revenue') that is, in turn, recovered from customers via annual network charges. The ARRs and expected revenue are equal NPV terms.

Figure 49: Regulatory Building Blocks for SCS



As outlined in Table 65, for the 2025-30 regulatory control period, we are proposing:

- total ARRs of $7,819 million
- total expected revenue of $7,819 million, and
- annual X-factors of -4.71 per cent, with the X-factors representing the real change in expected annual revenue and negative X-factors implying an increase in revenue.

Table 65: Proposed 2025-30 ARR, expected revenue and X-factors

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Return on capital	955.3	992.5	1,032.6	1,078.5	1,125.5	**5,184.3**
Regulatory depreciation	202.0	220.5	236.4	251.1	247.1	**1,157.1**
Opex	470.8	473.6	476.4	477.9	480.4	**2,379.1**
Revenue adjustments	-191.5	-202.8	-207.8	-162.3	-141.2	**-905.6**
Tax allowance	0.0	0.0	0.0	1.9	2.2	**4.0**
ARR (unsmoothed)	1,436.6	1,483.7	1,537.5	1,647.1	1,713.9	**7,818.9**
Annual expected revenue (smoothed)	1,423.3	1,490.3	1,560.5	1,633.9	1,710.9	**7,818.9**
X-factors[2]	-4.71%	-4.71%	-4.71%	-4.71%	-4.71%	

Notes:
1. Totals may not add due to rounding.
2. Negative X-factor implies an increase in revenue.

For the first time since our first distribution determination under the AER (for the 2010-15 regulatory control period), we are proposing an increase in our total revenue. Our proposed total ARRs are 15 per cent higher than in the current regulatory control period. The increase is driven by:

- a significant increase in our forecast return on capital (or financing costs). This is mainly due to factors outside our control, such as interest rates and inflation rising sharply since our last distribution determination. Figure 50 shows how the 10-year yield on Australian Government bonds (the proxy for the risk-free interest rate) has increased from the historical lows experienced at our last determination in 2020, to current 12-year highs. In addition, the increase in the forecast return on capital is also driven by higher capex in the current and next regulatory control periods, and
- an increase in our forecast opex forecasts.

The revenue increase is offset by material negative revenue adjustments because of the penalties we forecast to incur under the AER's capex and opex incentive schemes. That is, the revenue increase in the next regulatory control period would be materially higher in the absence of the revenue adjustments.

Figure 51 and 52 show the trends in our revenues since 2010 and the key drivers of the revenue increase from the previous period, respectively.

Figure 50: Australian Government 10 year bond yield

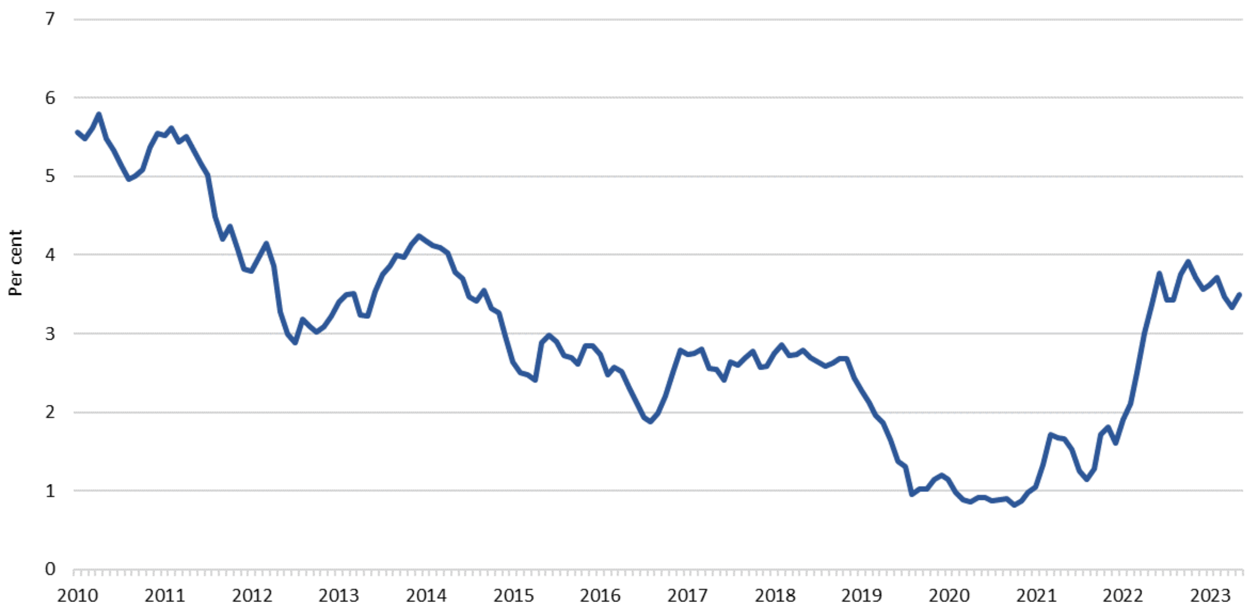


Figure 51: Total unsmoothed revenue ($m, real 2024-25)

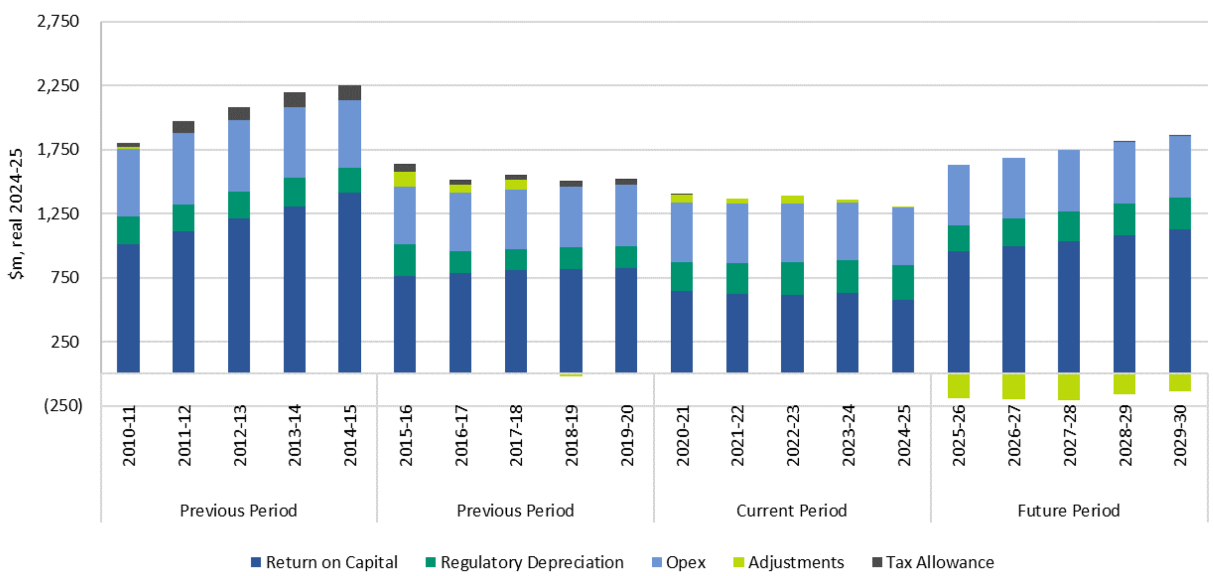
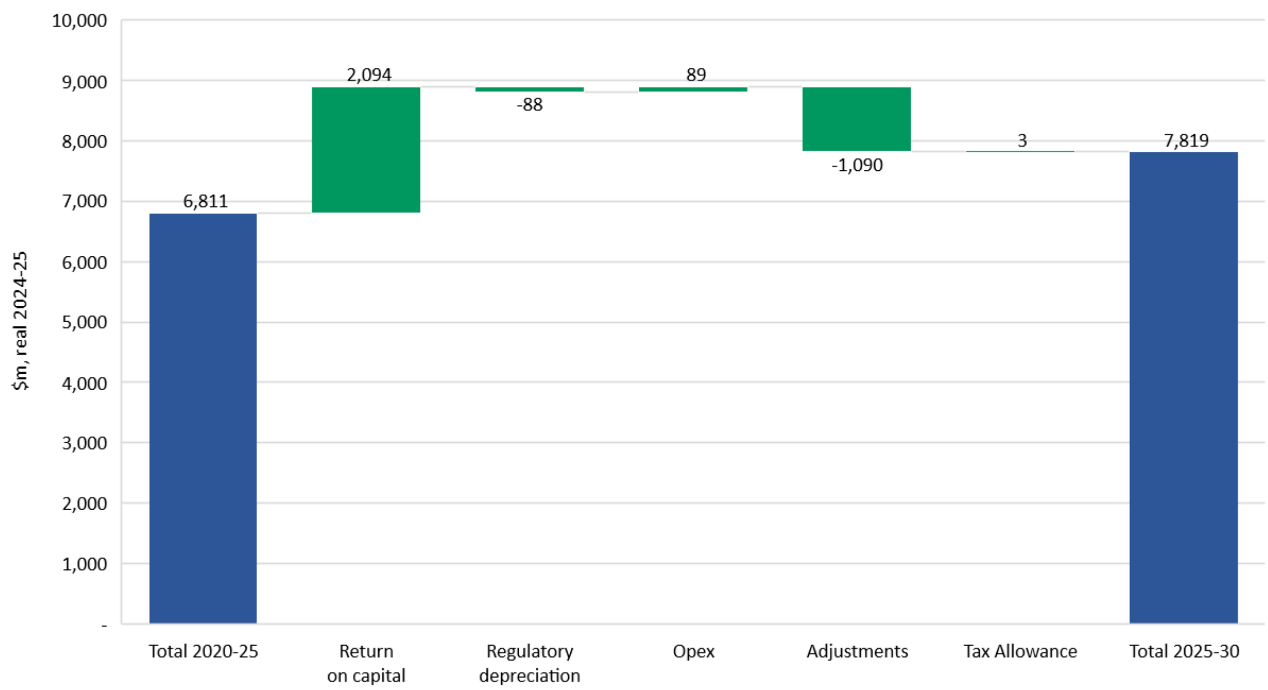


Figure 52: Revenue changes from previous regulatory control period ($m, real 2024-25)

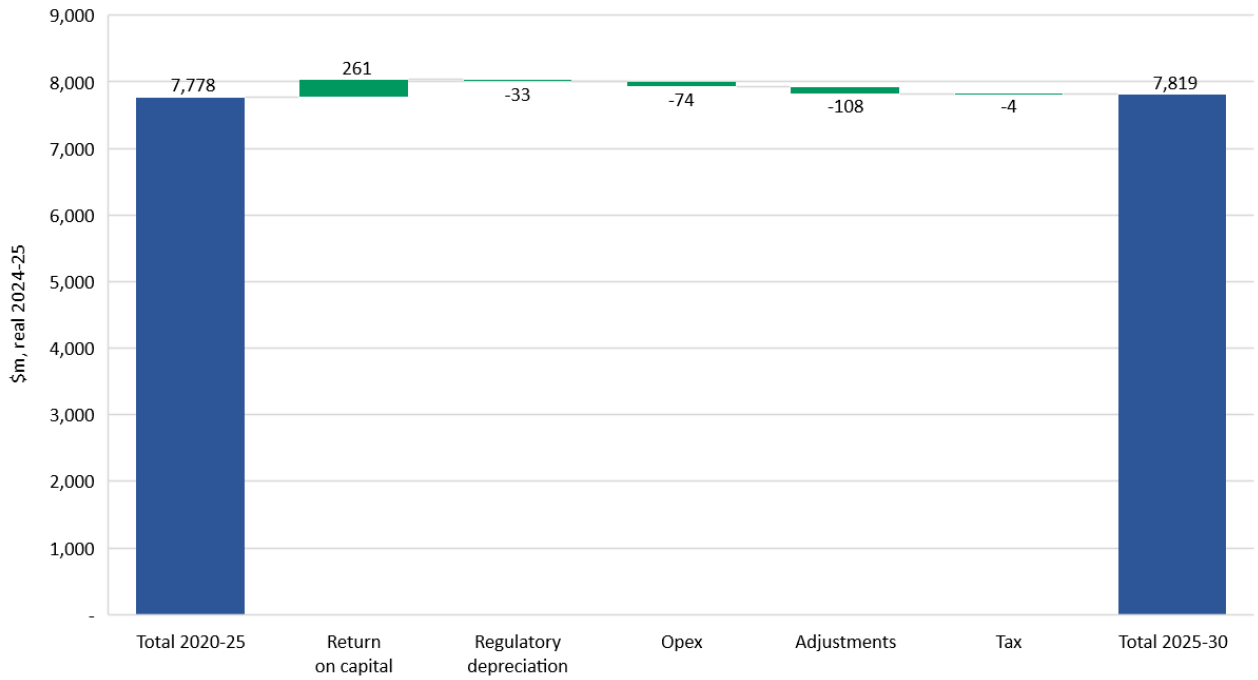


8.3 Changes from our Draft Plan

Our proposed revenues for the 2025-30 regulatory control period have increased by 0.5 per cent relative to our Draft Plan. The increase in revenue is driven by interest rates continuing to rise, which is beyond our control. We have updated the forecast rate of return to 6.19 per cent from 5.90 per cent and this has materially increased our forecast revenue and specifically our return on capital. This increase in the forecast rate of return has more than offset the significant reductions that we made to our forecast opex.

Figure 53 shows the changes in the building blocks from our Draft Plan.

Figure 53: Revenue changes from the Draft Plan



8.4 Regulatory asset base

The RAB is the total unrecovered value of the assets used to provide SCS to customers. The RAB for each year is calculated by rolling forward the RAB from the previous year by adding efficient new capex, adding inflation, and deducting depreciation and disposals of any existing assets.

The RAB has a substantial impact on our revenues (and network charges). It determines two of the building blocks that make up approximately 70 per cent of our revenues: the return on capital (financing costs) and regulatory depreciation (payback of investments).

For the 2025-30 regulatory control period, we are proposing:

- an opening RAB at the start of the regulatory control period (1 July 2025) of $16,253.0 million ($, nominal), and
- a closing RAB at the end of the regulatory control period (30 June 2030) of $21,388.7 million ($, nominal).

8.4.1 Value of the opening RAB - as at 1 July 2025

Table 66 sets out our proposed RAB at the commencement of the 2025-30 regulatory control period.

Table 66: Proposed RAB as at 1 July 2025

	Current Period				
$m, nominal	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**
Opening RAB	11,533.8	11,859.3	12,537.0	13,937.9	14,957.2
Net Capex	674.9	730.2	913.2	986.9	1,053.2
Indexation	99.3	414.9	981.9	571.5	493.6
Straight-line depreciation	-448.7	-467.3	-494.3	-539.0	-575.6
Interim closing RAB	11,859.3	12,537.0	13,937.9	14,957.2	15,928.4
Adjustment for previous regulatory control period					271.0
Final year adjustment					53.6
Opening RAB value as at 1 July 2025					16,253.0

We have used the AER's roll-forward model (RFM) to roll-forward the RAB across the current regulatory control period to 1 July 2025.

8.4.1.1 Ex post prudency and efficiency review of capex

In accordance with the NER, the AER must provide a statement on the extent to which the roll-forward of the RAB contributes to the achievement of the capex incentive objective.[20] The capex incentive objective is to ensure that, where the value of a RAB is subject to adjustment in accordance with the NER, then the only capex that is included in an adjustment that increases the value of that RAB is capex that reasonably reflects the capex criteria (i.e. capex that is prudent and efficient).[21] The NER further states that the AER may adjust past capex where a distributor has, amongst other things, overspent the AER's capex forecasts.

The relevant period for the AER's ex post assessment for our 2025-30 distribution determination is the period from 2018-19 to 2022-23, i.e. the last two years of the previous regulatory control period and first three years of the current regulatory control period. Over this period, we have overspent the AER's capex forecasts. We consider that the overspend was prudent and efficient. We provide our justification for the expenditure in Attachment 8.01 and consider that the roll-forward of the RAB, including this capex, contributes to the achievement of the capex incentive objective.

However, as indicated in our Draft Plan, we are proposing to exclude $121.3 million of ICT capex that we incurred above the AER's forecasts over the ex post review period. Excluding this capex from the RAB reduces our forecast revenues by $109 million over the next regulatory control period. The revenue reduction accounts for the impact of incentive schemes.

8.4.1.2 Adjustment for capitalisation of lease costs

We propose to include a final year adjustment to the RAB to reflect the capitalisation of lease costs as a result of the change in lease accounting standards. The accounting standard AASB 16 *Leases* requires operating leases to be recognised on the balance sheet (capitalised) as a right-of-use asset instead of being expensed (treated as opex). While AASB 16 came into effect in our previous regulatory control period (on 1 January 2019), we have maintained the previous lease reporting arrangements for regulatory purposes in the current regulatory control period. We made

[20] Clause 6.12.2(b) of the NER.

[21] Clause 6.4A(a) of the NER.

this decision because it was still unclear how leases would be treated for regulatory purposes at the time of our last determination.

For the forthcoming regulatory control period, we are proposing to align our statutory and regulatory treatment of leases and include the present value of existing leases as at the commencement of the regulatory control period in the RAB (1 July 2025). Attachment 8.04 provides our calculations.

8.4.2 Value of the forecast RAB

Table 67 sets out our proposed forecast RAB across the 2025-30 regulatory control period. We have used the AER's PTRM to calculate the forecast RAB.

Table 67: Forecast RAB

	Future Period				
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Opening RAB	16,253.0	17,222.8	18,202.8	19,205.7	20,244.9
Net capex	1,177.4	1,213.1	1,259.7	1,319.6	1,427.5
Straight-line depreciation	-662.7	-715.3	-766.4	-818.2	-850.5
Indexation	455.0	482.2	509.6	537.7	566.8
Closing RAB	17,222.8	18,202.8	19,205.7	20,244.9	21,388.7

8.4.3 Establishing the RAB at the commencement of the 2030-35 regulatory control period

Consistent with the AER's Final F&A for the 2025-30 regulatory control period, we propose the use of forecast depreciation to determine the RAB at commencement of the 2030-35 regulatory control period.

8.5 Rate of return

The rate of return, or WACC, is an estimate of the benchmark financing costs we require to fund our investments in the network. The rate of return is determined by the AER in accordance with its *Rate of Return Instrument* and is calculated by combining the estimates of returns expected by lenders for providing debt and shareholders for providing equity. The AER does not set a specific rate of return for our business but sets a 'benchmark' that applies to all energy networks that it regulates.

Table 68 summarises our placeholder rate of return estimates used for this Regulatory Proposal.

Table 68: Rate of return estimates

	Future Period				
Per cent	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Return on equity	7.94%	7.94%	7.94%	7.94%	7.94%
Return on debt	4.78%	4.86%	4.98%	5.16%	5.34%
Gearing	60%	60%	60%	60%	60%
Rate of return	6.04%	6.09%	6.16%	6.27%	6.38%
Value of imputation credits (gamma)	57%	57%	57%	57%	57%

8.5.1 Return on equity

Table 69 set out our placeholder return on equity estimates. The return on equity is calculated in accordance with methodology and parameter values outlined in the AER's 2022 *Rate of Return Instrument*. We have used an averaging period of 20 business days to the end of September 2023 to estimate the placeholder risk-free rate. The final risk-free rate that will apply over the 2025-30 regulatory control period will be determined based on a future averaging period that we have nominated in Attachment 8.05, consistent with the AER's 2022 *Rate of Return Instrument*.

Table 69: Return on equity

Return on equity parameters	
Risk-free rate	4.22%
Equity beta	0.6
Market risk premium	6.20%
Return on equity	7.94%

8.5.2 Return on debt

We have applied the trailing average methodology to estimate the return on debt. The return on debt is updated annually. We have used the prevailing rates from the AER's 2023-24 return on debt estimate as the forward estimates to roll-forward the trailing average. Consistent with the AER's 2022 *Rate of Return Instrument*, we have nominated the averaging periods for estimating the prevailing return on debt in each year of the 2025-30 regulatory control period in Attachment 8.05.

8.5.3 Value of imputation credits

We have adopted 0.57 value of imputation credits (gamma) as set out in the AER's *2022 Rate of Return Instrument*.

8.5.4 Debt and equity raising costs

Debt and equity raising costs are transaction costs incurred in raising debt and equity respectively. Debt raising costs are expensed (added to opex) while equity raising costs are capitalised (added to the RAB) under the AER's current approach. We have applied the AER's preferred 'benchmark' methodologies to estimate debt and equity raising costs:

- the debt raising costs methodology is based on an assumed benchmark bond size, estimating the number of bond issues required to roll over the debt proportion of the RAB (60 per cent) over 10 years and amortising the upfront issuance costs using the nominal rate of return. We have estimated a benchmark unit rate of 8.4 basis points per annum and applied it to our forecast RAB, and
- the equity raising costs methodology is based on a cash flow analysis and estimates if an equity injection will be required based on the projected capex. We are not forecasting any equity raising costs for the next regulatory control period.

Our calculations are provided in the attached PTRM.

8.5.5 Expected inflation

We have estimated expected inflation based on the AER's methodology as set out in the PTRM. Expected inflation is estimated as the geometric average of inflation over the regulatory control period based on the Reserve Bank of Australia's (RBA's) short-term forecasts and a glide-path to the mid-point of the RBA's target inflation band in the fifth year. We have used the RBA's August *Statement of Monetary Policy* to derive a placeholder estimate of 2.80 per cent for this Regulatory Proposal.

8.6 Regulatory depreciation

Regulatory depreciation (or return of asset) is an allowance that reflects the payback of the RAB. The allowance allows investors to recover the value of their investment over the life of the assets. Regulatory depreciation is comprised of two components – indexation and straight-line depreciation. Given that the RAB is indexed to compensate Ergon Energy Network for actual inflation over time, forecast indexation is subtracted from depreciation to ensure that we do not recover inflation twice in recovering our allowable revenue.

Ergon Energy Network is proposing to retain the current year-by-year tracking methodology and standard asset lives approved in the last determination. We also propose to include two additional asset categories reflecting the proposed capitalisation of leases in the RAB. We are proposing one lease category with a standard life of 10 years to be used for long-life leases and another lease category with a short standard life of five years to be used for lease extensions or other short-term leases.

For the 2025-30 regulatory control period, we are forecasting a depreciation allowance of $1,157.1 million.

8.7 Corporate income tax

The tax allowance building block provides an allowance for the estimated cost of corporate tax. We are forecasting a tax allowance of $4.0 million. We have used the AER's PTRM provided as Attachment 8.03 to calculate the tax allowance and applied the following key assumptions:

- a corporate statutory taxation rate of 30 per cent
- a value of imputation credits (gamma) of 0.57
- immediate expensing of all our forecast capitalised overheads, consistent with our current taxation policy of immediately deducting these costs for taxation purposes
- a diminishing value depreciation method except for buildings, equity raising costs and in-house software
- retention of our current regulatory control period standard taxation lives, and
- an opening tax asset base of $9,575.7 million as at 1 July 2025, calculated using the AER's RFM and applying a year-by-year tracking approach.

8.8 Revenue adjustments

Revenue adjustments include:

- rewards or penalties Ergon Energy Network earns or incurs under the AER's incentive schemes (refer to Chapter 7), and
- adjustments to account for any unregulated revenue that we derive from shared assets.

Table 71 sets out our forecast revenue adjustments for the 2025-30 regulatory control period.

Table 70: Revenue adjustments

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
EBSS	-50.1	-61.5	-66.5	-21.0	0.0	**-199.0**
CESS	-142.9	-142.9	-142.9	-142.9	-142.9	**-714.6**
DMIAM	1.5	1.5	1.6	1.6	1.6	**7.8**
Total[1]	**-191.5**	**-202.8**	**-207.8**	**-162.3**	**-141.2**	**-905.6**

Note 1: Totals may not add due to rounding.

We have not included an adjustment for shared assets revenue as our revenue from shared assets does not meet the required materiality threshold of 1 per cent.

8.9 Operating expenditure

Opex refers to the non-capital expenses that we incur in operating and maintaining the distribution network for the benefit of our customers. We are forecasting opex of $2,379.1 million for the 2025-30 regulatory control period as discussed in Chapter 6. Our opex for 2025-30 is provided in Table 70.

Table 71: Opex

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Opex (excl. debt raising costs)	462.7	465.2	467.7	469.1	471.3	**2,336.0**
Debt raising costs	8.1	8.4	8.6	8.9	9.0	**43.1**
Total opex[1]	**470.8**	**473.6**	**476.4**	**477.9**	**480.4**	**2,379.1**

Note 1: Totals may not add due to rounding.

8.10 Smoothed revenues and X-factors

The sum of the building blocks for each year can fluctuate materially from year-to-year across the regulatory control period. To minimise the volatility in revenues and network charges, we smooth the revenue across the regulatory control period. In the smoothing process we recover the same amount of revenue in NPV terms. That is, we are neither better nor worse off.

We are proposing to depart from the AER's default smoothing approach in the PTRM and apply smoothing in a manner that results in equal revenue increases in each year of the regulatory control period (a negative X-factor represents a revenue increase). We consider that departing from the default smoothing approach minimises price shocks for customers in the first year of the next regulatory control period. The two revenue options are set out in Table 72.

Table 72: Revenue smoothing options ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Default smoothing (revenue)	1,436.6	1,497.3	1,560.6	1,626.6	1,695.4	**7,816.6**
Default smoothing (X-factors)	-5.69%	-4.23%	-4.23%	-4.23%	-4.23%	n/a
Our proposed smoothing (revenue)	1,423.3	1,490.3	1,560.5	1,633.9	1,710.9	**7,818.9**
Our proposed smoothing (X-factors)	-4.71%	-4.71%	-4.71%	-4.71%	-4.71%	n/a

Note 1: Totals may not add due to rounding.

Our proposed smoothing approach satisfies the NER requirement for the smoothing process to minimise the difference between the unsmoothed revenue and smoothed revenue in the final year of the regulatory control period. The difference between the last year's smoothed and unsmoothed revenue under our proposed approach is 1.2 per cent, which is lower than the AER's threshold of 3 per cent.

In our Draft Plan, we tested our proposed smoothing approach with our customers and they overwhelmingly supported our proposed approach.

8.11 Bill impacts

We estimate that total annual network charges (inclusive of transmission charges and jurisdictional schemes) will increase, in nominal terms, by an average of $66 or 6.0 per cent annually for residential customers, $146 or 6.8 per cent annually for small business customers, and $4,342 or 7.1 per cent annually for a large business connected on the low voltage network.[22] The indicative bill impacts are outlined in Table 73.

[22] The price impacts factor in transmission charges from Powerlink that are forecast to increase by inflation and the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. For forecast inflation, we have used a forecast of 2.80 per cent based on the AER's methodology set out in the PTRM.

Table 73: Indicative bill impacts

$, nominal	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Average Annual change
Residential[1]							
Indicative annual bill	967	1,037	1,105	1,171	1,204	1,295	
Annual ($) change		69	68	66	33	91	66
Annual (%) change		7.2%	6.6%	6.0%	2.8%	7.6%	6.0%
Small business[2]							
Indicative annual bill	1,884	2,037	2,190	2,339	2,421	2,613	
Annual ($) change		152	154	149	81	193	146
Annual (%) change		8.1%	7.6%	6.8%	3.5%	8.0%	6.8%
Large low voltage business[3]							
Indicative annual bill	53,460	57,579	61,915	66,243	69,493	75,172	
Annual ($) change		4,119	4,336	4,327	3,250	5,680	4,342
Annual (%) change		7.7%	7.5%	7.0%	4.9%	8.2%	7.1%

Notes:
1. Residential typical customer: calculated as a weighted average of the bill impact on the residential inclining block tariffs and transitional demand tariffs at the total network level assuming annual energy usage of 5024kWh and monthly demand of 3.48kW.
2. Small business customer: customer on the default transitional demand tariff with annual consumption of 14,485kWh with a monthly peak demand of 7.41kW.
3. Large low voltage business typical customer: Customer on Demand Small Tariff with annual consumption of 380,917 with a monthly anytime demand of 59.76kVA.

We acknowledge that the forecast network bill impacts will heighten the affordability challenges faced by our customers. However, the projected increases to customers' bills are mainly due to uncontrollable factors. While our capex and opex requirements have grown and contributed to the forecast increases, interest rates and inflation have also rapidly increased since our previous determination for the 2020-25 regulatory control period and are the main reason for the forecast rise in network bills.

The indicative bill impacts are partly offset by incentive scheme penalties and business initiatives to address affordability concerns. Business initiatives that have been employed to minimise bill impacts include applying a 1 per cent productivity factor to opex and capitalised overheads, and the self-funding of ICT expenditure that exceeded the AER's forecasts from 2018-19 to 2022-23.

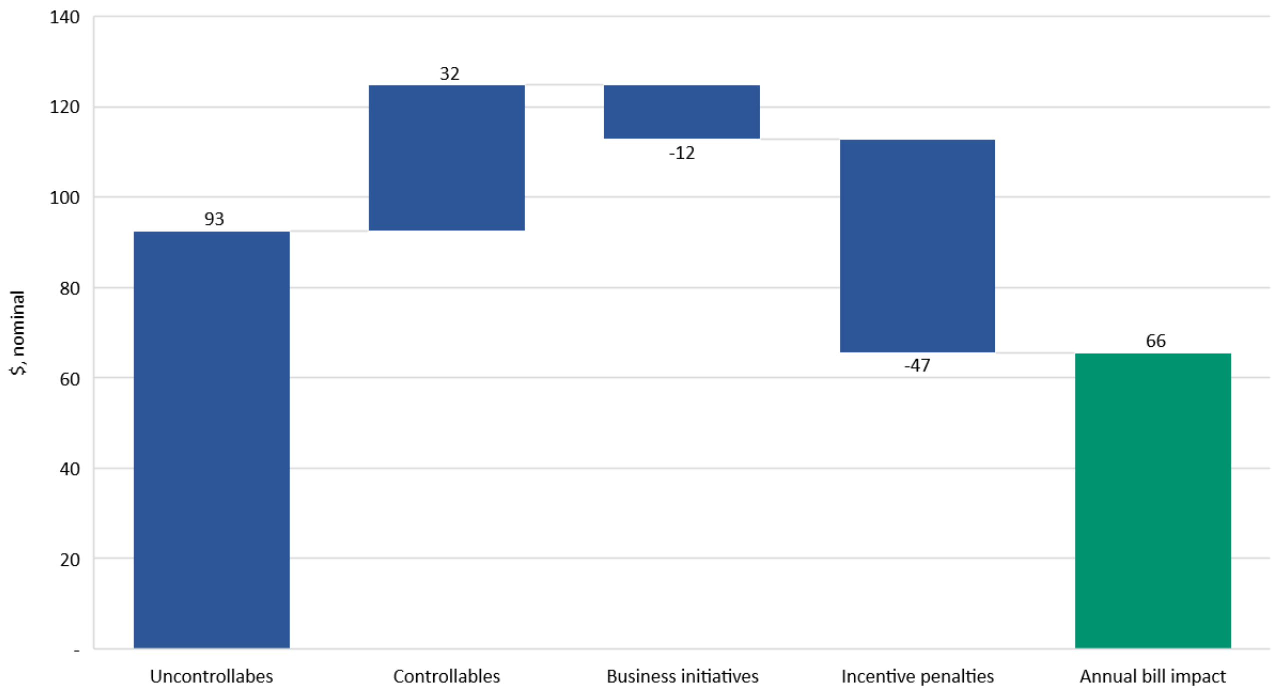
Figure 54 shows that the $66 average annual residential network bill increase is comprised of:

- $93 which is due to uncontrollable factors, being increasing interest rates and inflation, and
- $32 which is due to controllable factors, being the increase in our capital and opex requirements.

The increase in network bills is partly offset by:

- $12 from the previously mentioned business initiatives, and
- $47 which is due to incentive scheme penalties.

Figure 54: Drivers of indicative annual residential bill increase



8.12 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Model - SCS RFM	8.01	Ergon - 8.01 - Model SCS RFM - January 2024 – public
Model - SCS Depreciation model	8.02	Ergon - 8.02 - Model SCS Depreciation - January 2024 – public
Model - SCS PTRM	8.03	Ergon - 8.03 - Model SCS PTRM - January 2024 – public
Model - SCS Leases	8.04	Ergon - 8.04 - Model SCS Leases - January 2024 - public
Rate of return (averaging periods)	8.05	Ergon - 8.05 - Rate of return (averaging periods) - January 2024 – public Ergon - 8.05 - Rate of return (averaging periods) - January - 2024 - confidential

9.
Network Tariffs and Pricing

Key messages:

- Customers have told us they expect the industry as a whole to deliver simplicity, savings, value and choice, that rewards them for their role in the energy transition.
- In response to customer feedback, we are proposing changes to our network tariffs and assignment arrangements by strengthening the peak price signal, updating ToU pricing windows, transitioning to two-way pricing to support renewables, updating controlled load tariffs, and streamlining existing tariffs.
- These changes aim to align charges for using energy to the periods most likely to result in future investment and strive to improve the efficiency of prices passed through to retailers and customers.

Electricity affordability remains a concern for many of our customers, both from a cost-of-living and a business competitiveness perspective. Despite a number of years of relatively flat network tariffs, the current volatility in the wholesale energy market has seen an associated rise in retail electricity prices. Customers have told us they expect the industry as a whole to deliver simplicity, savings, value and choice, that rewards them for their role in the energy transition.

A customer's most regular interaction with the energy supply chain is usually through the payment of their energy bill to a retailer. A retailer's bill includes all costs associated with providing energy to the home or business, which includes Ergon Energy Network's costs. The network tariff is a combination of charges applied to each customer representing their contribution to the costs of distributing electricity. We bill retailers based on usage and the network tariff to which a customer has been assigned.

Our customers have expressed a strong interest in how changes in the amount of revenue we recover will impact them through the network tariff to which they are assigned by their retailer. Customers will be impacted by any change in revenue requirement between years but also by changes to the charging components in the tariff to which they are assigned.

Network tariffs and assignment arrangements are effectively reset every five years through the regulatory determination process with limited flexibility to make changes mid-period. Engagement on any proposed changes is therefore important. Our Tariff Structure Statement provides:

- details of how we assign retail customers to tariff classes and to network tariffs
- an explanation of new network tariffs, as well as tariffs we are proposing to close or withdraw and the implications for customers currently on those network tariffs, and
- an explanation of our approach to setting network tariffs in order to comply with the NER.

Our Tariff Structure Explanatory Statement provides further detail on how we arrived at our network tariff structures and charges for the 2025-30 regulatory control period. This includes the outcome of changes that applied in the current period, key drivers of further reform and how we have incorporated customer preferences and need for choice into our final designs.

We have also provided a separate attachment outlining network bill impacts (Attachment 9.02), reflecting the proposed changes in revenue recovery and the impacts of proposed changes in structure and assignment policies.

9.1 Summary of network tariffs

Ergon Energy Network has three tariff classes: Standard Asset Customers (SAC); Connection Asset Customers (CAC); and Individually Calculated Customers (ICC), as set out in Table 74.

Table 74: Network Tariff Classes

Tariff class	Eligibility criteria	Network tariffs
Standard Asset Customers	Customers connected at Low Voltage are classified as SAC. Customers may further be categorised as Small or Large	Tariff choice depends on customer type (i.e. residential vs business), annual consumption and meter type SAC Large are customers over 100 megawatt hours/annum
Connection Asset Customers	Customers with a network coupled to the Network Voltage from 11kV who are not allocated to the ICC tariff class are allocated to the CAC tariff class	Mix of site-specific & standard tariffs Tariff choice depends on connection characteristics i.e. voltage level, line vs bus connection
Individually Calculated Customers	Customers are allocated to the ICC tariff class if they are coupled to the network at 33kV or above. At discretion of the Network, we may permit customers coupled from 11kV in instances where 33kV is not available and there are no other voltages required for the bulk supply point	Site-specific distribution and transmission tariffs depending on connection assets, location and capacity requirements

9.2 Summary of tariff reforms proposed

Changes we implemented in our last Tariff Structure Statement in 2020 represented a significant but transitionary step towards more efficient tariff structures and assignment arrangements. We have seen further opportunities to build on reforms already introduced. Our aim is to improve the efficiency of our network tariffs so that customers can use and source energy in response to prices that are more closely aligned to the impact of customer decisions on our future network costs.

More efficient prices encourage more efficient use of the network, which can help reduce the need for additional investment over time. As all customers ultimately pay for network upgrades, improved pricing arrangements that encourage more efficient use of the network can lead to lower network costs for all customers.

Our proposed changes continue a national trend towards more efficient network tariff structures aimed at ensuring more efficient outcomes for all customers in relation to the use of electricity networks.

Table 75 summarises the proposed changes to our Tariff Structure Statement from 1 July 2025.

Table 75: Proposed changes to Tariff Structure Statement

What is changing	What is new	What is staying
Residential Customers		
• Default tariff structure is changing: – The peak window (4pm to 9pm) will apply a stronger long run marginal cost (LRMC) based maximum monthly demand charge – no distribution volume charges will apply in the peak demand window – Addition of a new window (11am to 4pm) and targeting a zero rate for distribution charges during this time – A new shoulder window will be introduced (9pm to 11am) – volume charges will apply during this time • Optional demand tariff will be withdrawn on 1 July 2025 – customers will be reassigned to the default tariff • Legacy ToU Energy tariff will be withdrawn from 1 July 2025 – this tariff has been closed to new customers since 2020 • Load Control tariff structure will be modified to allow for a fixed charge	• A new flexible load tariff will be available to customers from 1 July 2025 which supports large loads, like electric vehicles, under control while making use of their own solar or cheap daytime rates under primary tariffs • A two-way (export) tariff will be introduced from 1 July 2026. This tariff will have an export charge and export reward component. The tariff will be introduced for new customers from 1 July 2026 and all customers from 1 July 2028 (unless they opt into a dynamic connection) • A new optional demand tariff will be included for pilots and trials. This tariff will consist of only fixed and ToU demand charges for recovery of distribution revenue	• ToU Energy tariff will remain optional for smart meter customers • Inclining block tariff will remain open for basic meter customers only (inclining block tariff volume charges will be flattened)
Small Business Customers		
• Default tariff structure is changing: – The peak window (5pm to 8pm weekdays) will apply a stronger LRMC based maximum monthly demand charge – no distribution volume charges will apply in the peak demand window – Addition of a new window (11am to 1pm) and targeting a zero rate for distribution charges during this time – A new shoulder window will be introduced for all other periods – volume charges will apply during this time • Optional Demand tariff will be withdrawn from 1 July 2025 – customers will be reassigned to the default tariff	• A two-way (export) tariff will be introduced from 1 July 2026. This tariff will have an export charge and export reward component. The tariff will be mandatory for new customers from 1 July 2026 and existing customers from 1 July 2028 (unless they opt into a dynamic connection) • A new optional demand tariff will be introduced – this tariff will consist of only fixed and ToU demand charges for recovery of distribution revenue	• ToU Energy tariff will remain optional for smart meter customers • Inclining block and wide inclining fixed tariffs will remain open for basic meter customers only (inclining block tariff volume charges will be flattened) • Small Business Primary Load Control tariff will remain optional

What is changing	What is new	What is staying
• Three transitional non-cost reflective tariffs will be withdrawn from 1 July 2025		
Large Low Voltage Customers		
• Default tariff structure is changing: – A new off-peak window (11am to 1pm) will be introduced – volume charges will be set very low during this time – The peak window will be amended from 4pm to 9pm to 5pm to 8pm. Distribution volume charges will be removed from this window – it will be used to signal LRMC based demand charges – A new shoulder window will be introduced (1pm to 5pm and 8pm to 11am) – demand and volume charge will apply during this time • All customers will be reassigned from Demand Large, Medium and Small tariffs to the default tariff. Customers worse off will be able to opt-out back to Demand Small. Demand Large and Medium tariffs will be permanently withdrawn on 1 July 2025 • Seasonal tariff will be permanently withdrawn on 1 July 2025 - tariff has been closed to new customers since 2020	• A two-way (export) tariff will be introduced from 1 July 2026. This tariff will have an export charge and export reward component. The tariff will be mandatory for new customers from 1 July 2026 and existing customers from 1 July 2028 (unless they opt into a dynamic connection) • A new optional storage tariff will be introduced from 1 July 2025	• Large Business Energy tariff will remain open for basic meter customers only • Existing Large Business Primary Load Control and Secondary Load Control tariffs will remain unchanged
Large High Voltage Customers		
• Seasonal CAC tariffs will be permanently withdrawn on 1 July 2025	• Two new optional tariffs will be introduced for CAC customers: – a ToU Demand tariff with a peak demand charge applying from 5pm to 8pm and lower priced 11am to 1pm off-peak window, and – A storage tariff for customers with a dynamic connection	• ICC tariffs will remain unchanged • Default CAC tariffs will remain unchanged

9.3 Delivering for our customers

Our Tariff Structure Explanatory Statement provides details of our engagement with customers on tariff reform which commenced following approval of our last Tariff Structure Statement for 2020-25.

9.3.1 Early engagement (2021-22)

In anticipation of the evolving needs and expectations of customers, we commenced our engagement in 2021 to develop the initial approaches towards designing network tariffs that would cater for future customer and market needs. Input from our customers on a wide range of engagement activities has been invaluable in shaping our second phase pre-lodgement engagement for 2025-30.

This early engagement phase allowed us to build in modelling to provide key customer insights into addressing affordability concerns and providing value when implementing network tariff reforms into our pricing structures.

Further information on our early engagement phase can be found in our Tariff Structure Explanatory Statement.

9.3.2 Pre-lodgement engagement (2023)

Our Draft Plan proposed changes to tariffs and assignment arrangements following engagement revolving around five key network tariff themes:

- strengthening the peak price signal to ensure residential and small business tariffs better reflect the costs when demand on our network is highest
- updating our ToU charging windows to provide customers with more accurate price signals about the costs required to service demand at different times of the day, including both evening peak and day off-peak periods
- transitioning to two-way export pricing for low voltage customers to encourage exports during peak demand periods and self-consumption during the day
- updating our controlled load tariffs to ensure they continue to remain relevant to customers and to maximise the benefits for the network, and
- streamlining our existing tariff offerings to make it easier for electricity retailers to pass through our tariff structures and for customers to understand and respond to our price signals.

A summary of our pre-lodgement engagement is provided in Table 76.

Table 76: Pre-lodgement engagement for network tariffs

PHASE	TIME FRAME	ENGAGEMENT	TOPICS	OUTPUT
PHASE 1 GATHER & PLAN	By end-2022	• Tariff Reform Working Group - Residential (TRWG-R) Workshops • Public Lighting Forum • 1:1 Customer conversations – residential	• Public lighting tariffs • Tariffs, price signals, and incentives for modifying how and when electricity is used.	
PHASE 2 LISTEN	Feb – Jun 2023	• TRWG-R Workshops • Queensland Household Energy Survey • Energy Retailer – Individual conversations		
PHASE 3 SHARE & EXPLORE	Jun – Aug 2023	• Voice of the Customer (VoC) Panel • Energy Retailer Forum • Large Customer Forum • Network Pricing Working Group (NPWG) • Stakeholder Forum • Customer Focus Group • Talking Energy – Queensland's Energy Future Survey • 1:1 Small Business Customer conversations	• Network tariff structure engagement themes and tariff options • Proposed tariff changes • Proposed new tariffs • Pricing windows • Load control	• Engagement Reports - Large Low Voltage Customer, Major Customer, Stakeholder and Retailer Forums, the VoC, NPWG and Customer Focus Groups • Small Business Research Report
PHASE 4 TEST & REVISE	Sep 2023 – Jan 2024	• Draft Plan Webinars • Large / Major Customer Forum • VoC Panel • Retailer Forum • Customer Focus Groups • NPWG • Industry Group Meetings • 1:1 Conversations	• Overview of Draft Plan Priorities, Revenue and Tariffs • Customer Impact Analysis • Proposed new tariffs • Network tariff structures • Public lighting tariffs • Storage tariffs • Tariff assignment • Review of draft Tariff Structure Statement (TSS)	• Draft Plan • Draft Plan Feedback • Engagement Reports - Large Low Voltage Customer, Major Customer, Stakeholder and Retailer Forums, the VoC, NPWG and Customer Focus Groups • Regulatory Proposal and TSS
PHASE 5 FINALISE	Apr – Sep 2024	• Large / Major Customer Forum • Retailer Forum • NPWG • Industry Group Meetings • 1:1 Conversations • Customer Focus Groups	• Evaluate customer and stakeholder feedback to the AER Issues Paper • Review of tariffs • Customer Impact Analysis	• Revised Regulatory Proposal and TSS
PHASE 6 FUTURE	Apr 2025	• Retailer Forum • NPWG	• To be determined	• To be determined

9.4 Changes since our Draft Plan

We tested the outcomes of the proposed changes in the Draft Plan across several engagement streams, including retailer and major customer forums, our residential Voice of the Customer Panel and our Network Pricing Working Group. We have also reviewed submissions on the Draft Plan. Most of the proposed changes set out in the Draft Plan have been retained in our Regulatory Proposal. However, the following changes or additions have been included in our Tariff Structure Statement:

- **the assignment arrangement for customers who have received a smart meter other than through a new or upgraded connection** - rather than moving these customers to a transitional tariff (which is the current arrangement), we propose to delay the assignment of these customers to the default demand and energy tariff to the end of the following financial year
- **simplifying arrangements for flexible load control by removing the Super Economy Tariff from 1 July 2025, subject to technical assessment** - since publishing the Draft Plan we have determined that a single tariff for different infrastructure and operational arrangements has technical and practical difficulties and, on this basis, we propose to maintain the two secondary load control tariff arrangements
- **proposed changes to SAC Large customers** – while our proposed changes will remain, we are proposing that all customers will be assigned to the default tariff from 1 July 2025 with the option for customers to move to the legacy (Demand Small) tariff from this date. We further seek to offer a kW Demand version for those customers with meters incompatible with kVA (removing this feature from Demand Small), and
- **storage tariffs** - we have provided further details for our proposal, which will include a preferred dynamic connection pricing structure as well as a critical price structure (noting that we expect to engage on, and refine, our operational arrangements for critical peak price and rebate arrangements over the period as more storage customers connect).

9.5 Energy affordability and bill impacts

Our proposal responds to customer concerns around affordability by driving down controllable aspects of our expenditure program without compromising safety or reliability of the network.

Proposed changes to network tariffs and assignment arrangements strive to improve the efficiency of our prices passed through to retailers and customers. Our structures aim to align the charges for using energy to the periods most likely to result in future investment. This means that recovery of investment is allocated to customers who use the network more in these peak periods (rather than those who do not).

If more customers choose to use less energy during this period to save money, this defers or avoids the need for future investment, keeping network costs lower for everyone. In addition, because Ergon Energy Network cannot recover any more than the approved revenue, prices set higher in the peak period must be offset by lower prices in other periods. We have sought to take advantage of this by offering significantly lower prices in periods of the day where there is surplus generation from rooftop solar, providing even better signals to move energy to off-peak times.

Network tariff changes will impact customers differently. We have sought to retain optionality where possible in our tariff mix, either by offering discounted prices for load (or generation) flexibility, or options to move to alternative network tariffs if a retail customer is impacted significantly from change. We have also responded to customers' preference that we defer introduction of two-way tariffs until other structural changes have been embedded.

Details of customer impacts as a result of different tariff changes (as well as impacts of moving between different tariffs) can be found in Attachment 9.02.

9.6 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
2025-30 Indicative network prices	9.01	Ergon - 9.01 - 2025-30 Indicative network prices - January 2024 - public
Network Bill Impacts	9.02	Ergon - 9.02 – Network Bill Impacts - January 2024 - public
Endgame Economics - ToU charging windows analysis	9.03	Ergon - 9.03 - Endgame Economics ToU charging windows analysis - January 2024 - public
Standalone & Avoidable Cost Model	9.04	Ergon - 9.04 - Standalone & Avoidable Cost Model - January 2024 - public
Endgame Economics - LRMC model	9.05	Ergon - 9.05 - Endgame Economics LRMC model - January 2024 - public
Network Tariffs and Dynamic Controls	9.06	Ergon – 9.06 - Dynamic Analysis Network tariffs and dynamic controls - January 2024 – public

10.
Metering

Key messages:

- With affordability, energy inclusion and customer vulnerability being key concerns for many customers, we are proposing a change to how customers are charged for 'legacy' metering services.
- The *Power of Choice* reforms fundamentally changed our role in the provision of metering services, reducing it to managing and maintaining our legacy Type 6 (basic) meters as they are progressively phased out and replaced by smart meters.
- Legacy metering services are currently classified as an ACS (i.e. user-pays). We are proposing that the classification should be changed to SCS, with the costs to be recovered from all low voltage connected customers through network charges.
- We also propose to accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of the 2025-30 regulatory control period.
- We have adopted a limited building block approach to determine the revenue requirement for our metering services. For the 2025-30 regulatory control period, we propose a total ARR (unsmoothed) of $179 million.
- During the 2025-30 regulatory control period, the costs for providing metering services will be recovered from all customers through a daily fixed charge.
- While this proposed change will result in a modest contribution from all low voltage connected customers to the recovery of legacy metering charges, it will reduce the disproportionate cost burden on customers who will be the last to receive a smart meter, including vulnerable customers.

10.1 Overview

Our customer engagement has clearly highlighted that affordability, energy inclusion and customer vulnerability are key concerns for many customers. The transition towards a 100 per cent rollout of smart meters by 2030 has highlighted the potential for a small number of customers, including those facing financial hardship, to disproportionately bear the cost burden of paying the residual value of our 'legacy' metering services.

Therefore, based on the AER's guidance and customer and stakeholder feedback, we are proposing a change to the classification of metering services from the current 'user-pays' approach to sharing the costs across all low voltage connected customers. This proposed change in classification is intended to lessen the impact on customers who will be among the last to receive a smart meter, including vulnerable customers.

We are of the view that the incremental cost to be paid by customers for legacy metering services will ensure the smooth transition to a new technology without unfairly assigning these costs to a small cohort of customers who can least afford them. This modest contribution is in recognition that all customers should equally bear the costs of legacy meters.

10.2 Legacy metering services

Metering services are activities relating to the measurement of electricity supplied to and from customers through the distribution system. This includes meter reading, meter testing and maintenance, meter investigations and meter data services.

Ergon Energy Network is currently responsible for the provision of Type 6 (or 'legacy') metering services to residential customers and small business customers. Legacy meters are basic accumulation meters that can only measure the total amount of electricity consumed over a specified period and are read manually at the customer's premises usually every quarter (sometimes monthly). These differ from Type 4 (or 'smart') metering services that offer significantly more functionality and benefits to customers. Smart meters can measure how much and when electricity is consumed and can be read remotely. They enable customers to better understand and manage their electricity consumption. Retailers and other third parties are responsible for the provision of smart metering services.

The current regulatory framework for metering services has been in place since the AEMC's 2015 *Power of Choice* reforms opened up competition from 1 December 2017. Prior to *Power of Choice*, metering services for residential and small business customers were a core part of Ergon Energy Network's regulated monopoly services. The AEMC's reforms fundamentally changed our role in the provision of metering services, reducing it to managing and maintaining our legacy meters as they are progressively phased out.

Legacy metering services are currently classified as an ACS and charged to customers on a user-pays basis. Charges are separated into two components:

- **capital charges** – which allow us to recover our investment in legacy meters over their remaining life, i.e. the legacy metering asset base. These charges are incurred by all customers who had a legacy meter installed prior to 30 June 2015 – even if they no longer have a legacy meter installed, and
- **non-capital charges** – which allow us to recover the efficient costs of operating and managing the legacy meters, such as meter reading and data services. These charges are only incurred by customers who still have a legacy meter installed.

10.3 Proposed reclassification of legacy metering services

On 3 July 2023, the AER published the Final F&A for the 2025-30 regulatory control period. In the Final F&A, the AER maintained an ACS classification for legacy metering services but expected our Regulatory Proposal to depart from this service classification following the finalisation of the AEMC's *Review of the regulatory framework for metering services* (*Metering Services Review*). The AER considered that the *Metering Services Review* would constitute a material change in circumstances justifying a departure from the F&A.

On 30 August 2023, the AEMC published its Final Report on the *Metering Services Review*. Consistent with the subsequent guidance provided by the AER in the Final F&A, we propose that legacy metering services should be reclassified as a SCS.

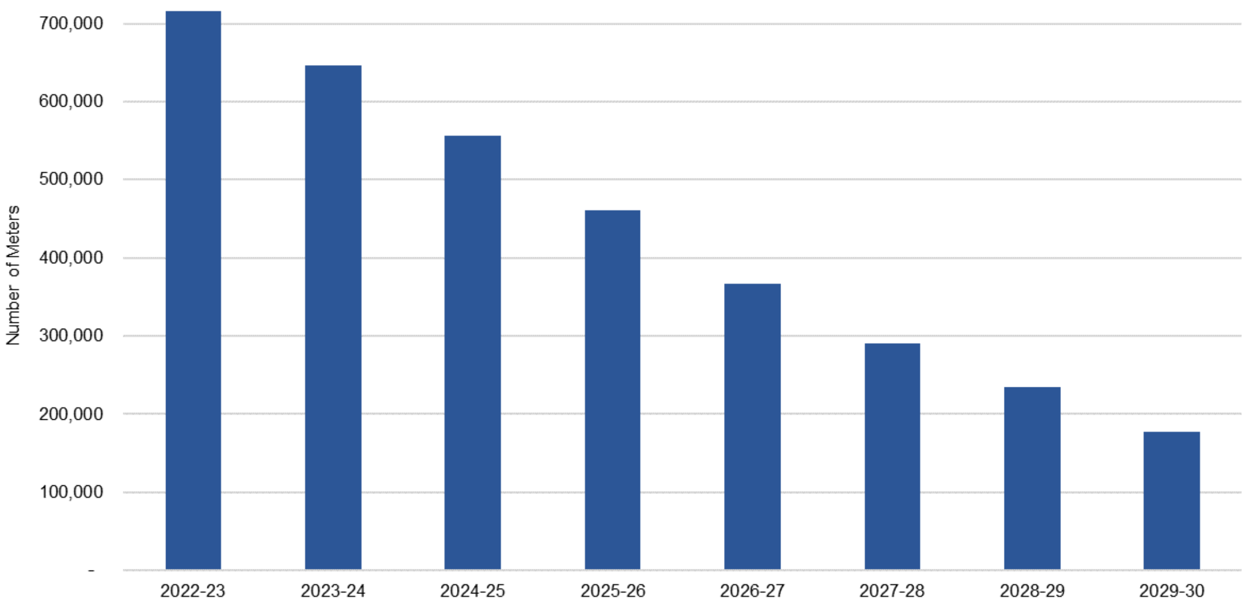
The reason for reclassifying legacy metering services as a SCS stems from the AEMC's recommendation for a pathway to achieve 100 per cent uptake of smart meters by 2030. This recommendation is consistent with the Queensland Government's *Queensland Energy and Jobs Plan* target of 100 per cent penetration of smart meters by 2030. As the deployment of smart meters accelerates, the non-capital charges per unit (faced by customers with legacy meters) are expected to materially increase. This is because we must spread our costs over fewer customers. The increase in non-capital charges per unit will be driven by:

- the anticipated increase in legacy meter investigations and queries, and
- scheduled meter reading costs which are estimated to remain constant due to the need to travel the same distance to read meters which are yet to be replaced, regardless of the number of meters.

The reclassification to SCS allows us to spread the recovery of legacy metering costs to all customers and prevent the burden of those costs falling mostly on customers who may face some type of difficulty in the transition, with financial hardship being potentially one of the main reasons.

Figure 55 shows Ergon Energy Network's forecast of the volumes of legacy meters to 2029-30.

Figure 55: Ergon Energy Network's legacy meter forecasts



The data supporting Figure 55 is provided in Table 77.

Table 77: Legacy Meter Forecast

	Current Period			Future Period				
	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Number of meters	715,132	646,090	555,590	461,030	366,471	290,823	234,087	177,351

10.4 Treatment of Mount Isa-Cloncurry network

In addition to our national grid-connected distribution network, the AER is also responsible for the economic regulation of our Mount Isa-Cloncurry network. As the Mount Isa-Cloncurry network is not connected to the national grid, the AEMC metering reforms do not apply in the area. Despite this, we propose that metering services in the Mount-Isa Cloncurry network should be treated consistently with our grid-connected distribution network and be reclassified as SCS. We consider that treating the Mount Isa-Cloncurry network in the same way as the grid-connected network is consistent with previous AER decisions.

The AER reclassified metering services in the Mount Isa-Cloncurry network as ACS in the 2015-20 distribution determination despite the network being exempt from the AEMC's *Power of Choice* reforms. It will be administratively burdensome to treat the Mount Isa-Cloncurry network differently to the grid-connected network. Metering costs for the Mount Isa-Cloncurry network is immaterial relative to Ergon Energy Network's overall metering costs. This area has approximately 1 per cent of Ergon Energy Network's customers.

More importantly, we consider that Mount Isa-Cloncurry metering services must be treated similarly to the grid-connected network due to the application of the Uniform Tariff Policy in Queensland. The Uniform Tariff Policy means that customers in the isolated networks will pay South East Queensland equivalent tariffs which will include Energex's legacy metering costs reclassified as SCS.

10.5 Delivering for our customers

In our Draft Plan, we discussed the potential change to the classification of legacy metering services from ACS to SCS, the intent being to support a pathway towards achieving an accelerated 100 per cent smart meter penetration by 2030 while at the same time managing customer impact. The AER's view was that, as the deployment of smart meters accelerates, the charges per unit faced by legacy meter customers would be expected to materially increase. A potential solution was to reclassify legacy metering services to SCS so the costs could be spread across all customers through network charges.

In the Draft Plan we sought customer feedback on the potential change in charging arrangements for legacy metering services from a user-pays approach to recovering the costs from all customers. While feedback received on the question posed in the Draft Plan showed broad support for the smart meter rollout, opinions were split on the cost recovery options. Some customers preferred the user-pays approach due to equity concerns while other customers and some key stakeholders such as the Queensland Consumers' Association and the RRG, supported the sharing of costs among all customers to manage customer impact during the transition to the new smart meter technology. The RRG provided its support for the potential change in charging arrangements for legacy metering services as it seeks to provide fair and equitable charging arrangements for customers, whilst supporting the objectives of the AEMC and the Queensland Government in achieving a 100 per cent smart meter deployment in Queensland by 2030. The RRG expected to see quantification of the bill impacts for different customer cohorts as part of engagement with customers on this proposed change.[23]

[23] Submissions on the Draft Plan can be accessed on our Talking Energy webpage.

The matter was also explored at two customer engagement sessions held on 21 and 22 October 2023. In addition to the potential reclassification of legacy metering services, we sought feedback on the option to accelerate the depreciation of our legacy metering fleet to ensure full recovery of our capex is achieved by the end of the 2025-30 regulatory control period. Participants generally supported the reclassification and accelerated recovery of depreciation on legacy meters by 2030 after being presented the analysis showing minimal impact on customers.

10.6 Proposed metering revenue

We have adopted a limited building block approach to determine the revenue requirement for our metering services. We have applied the same rate of return for metering services as for SCS and adopted the AER's PTRM straight-line depreciation approach and the AER's preferred base-step approach for our forecast opex.

As outlined in Table 78, for legacy metering services in the 2025-30 regulatory control period, we propose:

- total ARR (unsmoothed revenue) of $179.1 million
- total smoothed revenue of $179.7 million, and
- annual X-factors of -0.19 per cent.

Table 78: Forecast legacy metering revenue ($m, nominal)

	Future Period					
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Return on capital	2.5	2.1	1.6	1.1	0.6	**8.1**
Depreciation	7.5	7.9	8.4	8.9	9.4	**42.2**
Opex	25.4	25.6	25.8	26.1	26.1	**128.9**
Tax	-	-	-	-	-	**-**
ARR	35.4	35.6	35.8	36.1	36.1	**179.1**
Smoothed revenue	33.8	34.9	35.9	37.0	38.1	**179.7**
X-factors	-0.19%	-0.19%	-0.19%	-0.19%	-0.19%	

Note 1: Totals may not add due to rounding.

In developing our metering revenue proposal, we factored in the AER's November 2023 *Legacy metering services - Guidance note* (guidance note) provided to the New South Wales, Australian Capital Territory, Tasmania and Northern Territory distributors. In the guidance note, the AER stated that, in addition to the reclassification of legacy metering services from ACS to SCS, DNSPs should continue to develop their expenditure and revenue forecasts for legacy metering services using their own specific RFM and PTRM. This means that the RAB and opex forecasts for the main SCS and legacy metering services should be considered separately. As such, the AER expects two sets of ARRs, with legacy metering services being treated separately as a subset of SCS.

In the following sections we outline our key inputs and assumptions.

10.7 Metering RAB

Since the *Power of Choice* reforms commenced on 1 December 2017, we have remained responsible for Type 6 metering services. For the 2025-30 regulatory control period we will continue to recover the capital costs of Type 6 meters installed prior to 1 December 2015. The metering asset base represents our current unrecovered capital costs that we will recover via the return on capital, depreciation and tax revenue building blocks.

We propose an opening metering RAB of $42.2 million as at 1 July 2025. We have calculated this value using the AER's RFM (Attachment 10.03). Consistent with the AER's guidance note, we propose to accelerate the recovery of the metering RAB by 2030. We also propose to not add any new capex. Table 79 provides our forecast metering RAB over the 2025-30 regulatory control period as calculated using the AER's PTRM (Attachment 10.04).

Table 79: Forecast legacy RAB ($m, nominal)

	Future Period				
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
Opening value	42.2	34.7	26.7	18.3	9.4
Straight-line depreciation	-8.7	-8.9	-9.2	-9.4	-9.7
Indexation	1.2	1.0	0.8	0.5	0.3
Closing value	34.7	26.7	18.3	9.4	0.0

In calculating our proposed return of capital building blocks we have adopted the same rate of return assumptions as the main SCS.

10.8 Operating expenditure

Our forecast opex reflects the costs we continue to incur in providing legacy metering services related to:

- meter maintenance – works to inspect, test, maintain, repair and replace meters
- meter reading – quarterly or other regular reading of the meter, and
- meter data services – collection, processing, storage, delivery and management of metering data, remote or self-reading at difficult to access sites, provision of metering data from the previous two years and ongoing provision of metering data.

Our forecast opex uses the base-step-trend approach consistent with the AER's guidance note. Under this approach, we have:

- used 2023-24 metering opex as the base opex. We have used a forecast that we will update with actuals in our Revised Regulatory Proposal
- trended the opex using our expectations of volumes in line with the *Metering Services Review*. The AER notes that the AEMC has provided for several exemptions to this 100 per cent smart meter target by the end of 2029-30. While we acknowledge full smart meter deployment is the objective, we also note that in line with other jurisdictions that have experienced similar metering changes, there will be a small number of sites (estimated to be 15 per cent of our current meter population) that cannot be transitioned within the 2025-30 timeframe due to reasons such as switchboard constraints or access issues. These sites will need to be exempted, and

- applied a weighting to volume trend of 20 per cent to reflect the fact most of our costs are fixed. Meter reading operations (which represent 70 per cent of our total opex) are expected to remain relatively constant. With the smart meter rollout, some routes will ultimately be cancelled, but it is envisaged that some pockets will remain on legacy meters, resulting in similar routes to be travelled by our meter readers. In addition, with the loss in economies of scale, meter reader service providers are increasingly reluctant to continue providing this service unless the negotiated prices sufficiently compensate them for their effort.

Further details on our forecast opex are provided in Attachment 10.02.

In line with the *Metering Services Review* recommendations, we have prepared:

- a Legacy Meter Retirement Plan (LMRP), effective 1 July 2025, with the view to retire 15 to 25 per cent of meters from our fleet of legacy meters each year[24]
- a Legacy Meter Explanatory Statement (Attachment 10.01), and
- a Meter Asset Management Strategy (Attachment 10.06).

These documents set out our plans and forecast expenditure for our legacy metering services, including:

- implementation and monitoring of our newly developed LMRP
- testing and inspection of legacy metering installations for which we are responsible
- meter data services, noting that the costs associated with maintaining these systems and functions are fixed and not dependent on the number of meters
- meter reading operations, noting that the meter reading costs are not going to decrease at the same pace as the reduction in legacy meter numbers
- meter investigation requests, and
- meter family sample testing.

To achieve this, the unit cost per meter read is expected to increase.

Further details on our forecast opex are provided in Attachment 10.02.

10.9 Customer impacts

Table 80 shows the forecast annual metering services charges under the current user-pays arrangements in the last year of the current regulatory control period and the impact of recovering those charges from all low voltage connected customers during the 2025-30 regulatory control period. During 2025-30, these costs will be recovered from all customers through a daily fixed charge.

[24] Ergon Energy Network's LMRP will be submitted to the AER in a separate process to the 2025-30 Regulatory Proposal.

Table 80: Forecast metering services annual charges ($, nominal)

	Current Period	Future Period				
$, nominal	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**
ACS Primary Capital Metering Charge	19.04					
ACS Primary Capital and Non-Capital Metering Charge	70.98					
Annual Metering Charge ($/year)		43.75	44.69	45.65	46.65	47.69

While reclassifying legacy metering services as SCS would result in some customers currently not paying regulated metering charges needing to contribute to the recovery of legacy metering charges, it would reduce the cost burden on customers who will be the last to receive a smart meter, including vulnerable customers.

Our proposed prices for legacy metering services are provided in Attachment 10.5.

10.10 How this differs from our Draft Plan

Differences from our Draft Plan include:

- the AER's publication of its decision on the classification of legacy metering services, and its expectations in terms of the approach to be adopted by DNSPs in their expenditure forecasts and pricing methodologies
- adoption of the accelerated option for the recovery of legacy meter depreciation, and
- adoption of the AER's base-step-trend approach to develop our opex forecasts.

10.11 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Legacy Metering Explanatory Statement	10.01	Ergon – 10.01 - Legacy Metering Explanatory Statement – January 2024
Metering Expenditure Model 2025-30	10.02	Ergon – 10.02 – Metering Expenditure Model 2025-30 – January 2024
Metering RFM 2025-30	10.03	Ergon – 10.03 - Metering RFM 2025-30 – January 2024
Metering PTRM 2025-30	10.04	Ergon – 10.04 – Metering PTRM 2025-30 – January 2024
Metering Pricing Model 2025-30	10.05	Ergon – 10.05 – Metering Pricing Model 2025-30 – January 2024
Metering Asset Management Strategy 2025-30	10.06	Ergon – 10.06 – Metering Asset Management Strategy 2025-30 – January 2024

11.
Alternative Control Services

Key messages:

- We provide a range of ACS to customers, including public lighting, security lighting, connection management services, and ancillary services.
- With customer support, we propose to convert all existing conventional public lights to LED by 30 June 2030.
- From 1 July 2025, we propose to fund the capital costs of the conversion of the legacy customer-funded conventional lights to LED, with the capital charge recovered from a new tariff (Rate 2A).
- With customer support, we propose to offer smart control devices on a 'user-pays' basis, with customers funding the capital cost of the assets and gifting the assets to us to operate and maintain. A new smart control tariff (Rate 2B) will be introduced from 1 July 2026.
- Due to the low uptake of the Rate 4 tariff option during the 2020-25 regulatory control period, we propose to retire the Rate 4 tariff from 1 July 2025, with the existing Rate 4 assets reassigned to a Rate 2 LED tariff.
- Our proposed revenue requirement for public lighting services for the 2025-30 regulatory control period is $143 million ($, nominal). This is 1.4 per cent higher than the revenue we expect to recover from public lighting services in the current regulatory control period.
- We are proposing to cease offering security lighting as a new installation from 1 July 2025. However, we will continue to maintain and operate legacy security lights.
- Indicative 2025-26 prices for legacy security lights will be based on the 2024-25 prices escalated using CPI minus X.
- We are proposing to consolidate our fee-based ancillary services from 1 July 2025 by discontinuing a number of services which have had little to no uptake.

11.1 Overview

ACS are distribution services that are customer-specific or customer-requested services. Some of these services have the potential to be provided on a competitive basis rather than by a regulated DNSP. ACS are akin to a 'user-pays' system as the whole cost of the service is paid by the customer who seeks the service, rather than recovered from all customers. In line with the AER's Final F&A for the 2025-30 regulatory control period, the following services or service groups are classified as ACS:

- public lighting (including security lighting)
- connection management services
- enhanced connection services, and
- ancillary services (quoted and fee-based services).

From 1 July 2025, we are proposing that legacy metering services will cease to be classified as ACS and will become SCS. Further details are provided in Chapter 10.

A detailed discussion on ACS is provided in Attachment 11.09.

11.2 Public lighting

11.2.1 Overview of public lighting

Ergon Energy Network owns, operates and maintains about 153,000 public lights and keeps billing records for another 16,300 public lights owned and maintained by 68 councils and the Department of Transport and Main Roads. The provision of public lighting is a critical service that plays an important role in road safety and enhancing security in public areas.

In the next regulatory control period, our aim is to convert all of our conventional public lights to LED technology due to improved reliability and efficiency, and reduced environmental impact. In response to customer expectations and environmental concerns about mercury products, we have adopted a phased approach to LED conversion during the current 2020-25 regulatory control period, starting with the replacement of our legacy mercury vapour luminaires. By 30 June 2025, we will have replaced 80 per cent of our mercury vapour assets, or 40 per cent of our total conventional lights, with LED lights.

We have engaged in extensive consultation with our customers regarding the continued deployment of LED lights for the 2025-30 regulatory control period. We are pleased to note that, in response to our Public Lighting Issues Paper[25] and Draft Plan[26] published in July 2023 and September 2023 respectively, Ergon Energy Network's preferred option for an accelerated 100 per cent LED deployment target by 2030 has been endorsed by all respondents.

11.2.2 Our customer and stakeholder engagement

Because of the specific nature of public lighting service provision and the relatively small number of public lighting customers, we decided to have a standalone, discrete engagement for public lighting. Our engagement approach is in line with best practice guidelines, using the consultation spectrum developed by the IAP2 and the AER's *Better Reset Handbook* as its foundation. This approach also aligns with the approach adopted as part of our broader Regulatory Proposal process. Depending on the stage of the engagement and the issue to be discussed, we have adopted the relevant level of engagement. Starting in November 2022, the initial sessions with councils and the Department of Transport and Main Roads focused on the 'Inform' part of the IAP2 consultation spectrum, allowing customers sufficient time to build understanding. The matters covered during these first few sessions included the Regulatory Proposal process, the mechanics of our revenue and tariff setting process, an update on our achievements and issues identified during the 2020-25 regulatory control period, and our proposed 2025-30 public lighting strategy.

Our engagement has gradually transitioned from information sharing to more active, interactive and engaged consultation with our customers and stakeholders. Subsequent individual and group sessions have provided customers and stakeholders the opportunity to influence the 2025-30 public lighting strategy that will shape our proposed capex, opex, revenue and tariffs. To empower our customers with knowledge, we also published six fact sheets covering topics such as the regulatory determination process, how we derive our public lighting revenue and prices, smart cells and the AEMC's review of the metering arrangements for this new technology.

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[25] Ergon Energy Network's Public Lighting Issues Paper is available on our Talking Energy webpage.

[26] Ergon Energy Network's proposed public lighting strategy is discussed in Chapter 11 of our Draft Plan published on our Talking Energy webpage.

In early July 2023 we published a Public Lighting Issues Paper seeking feedback on five key issues that will influence our 2025-30 public lighting strategy and Regulatory Proposal. Those key issues included:

- the pace of the LED rollout for the 2025-30 regulatory control period
- proposed changes to the suite of public lighting tariffs
- managing customer impact with regards to the recovery of the residual value of conventional lights
- funding of the conversion of the Rate 2 assets to LED, and
- options for the deployment of smart cells.

We reflected customer responses in our Draft Plan, published in September 2023, and sought further feedback.

Figure 56 below shows the various stages of our public lighting engagement over the past 14 months.

Figure 56: Public lighting engagement stages

As part of our engagement, we sought customer feedback on the adequacy of our engagement approach and whether customers felt their feedback had been reflected in our strategy. Respondents were supportive of our approach and felt they had been adequately informed throughout the process and provided with opportunities to shape our strategy. This view was echoed by the RRG in their submission to our Draft Plan.[27]

Further details on our public lighting engagement are provided in Attachment 11.09.

[27] Reset Reference Group, *Response to the Ergon Energy Network Draft Plan*, October 2023.

11.2.3 Our proposed public lighting strategy

Our proposed 2025-30 public lighting strategy is the result of more than 14 months of customer and stakeholder engagement. We have canvassed the views and feedback received through our group and individual customer engagement sessions, surveys and discussion papers. A summary of our proposed public lighting strategy is provided below.

11.2.3.1 LED deployment strategy

Following customer feedback, our priority for the 2025-30 regulatory control period is to convert all remaining conventional lights to LED by 30 June 2030, including the legacy customer-funded conventional lights (known as 'Rate 2' conventional lights).

To manage customer impact, we will extend the recovery of the residual value of the conventional assets beyond 2030. This approach was communicated to our customers as part of our engagement and was unanimously supported.

11.2.3.2 Public lighting tariff strategy

For the 2025-30 regulatory control period, we propose to keep Rate 1 and Rate 2 tariffs unchanged. This aligns with the feedback received from customers during our engagement. Rate 2 tariffs will only recover the operating costs associated with the maintenance of contributed assets gifted to Ergon Energy Network, and a 10 per cent capital charge to cover the cost of replacing the Rate 2 assets upon failure or when reaching end-of-life.[28]

To keep the number of public lighting tariffs to a minimum, we have decided to retire Rate 4 which has had very limited uptake during the 2020-25 regulatory control period and introduce two new tariffs, namely:

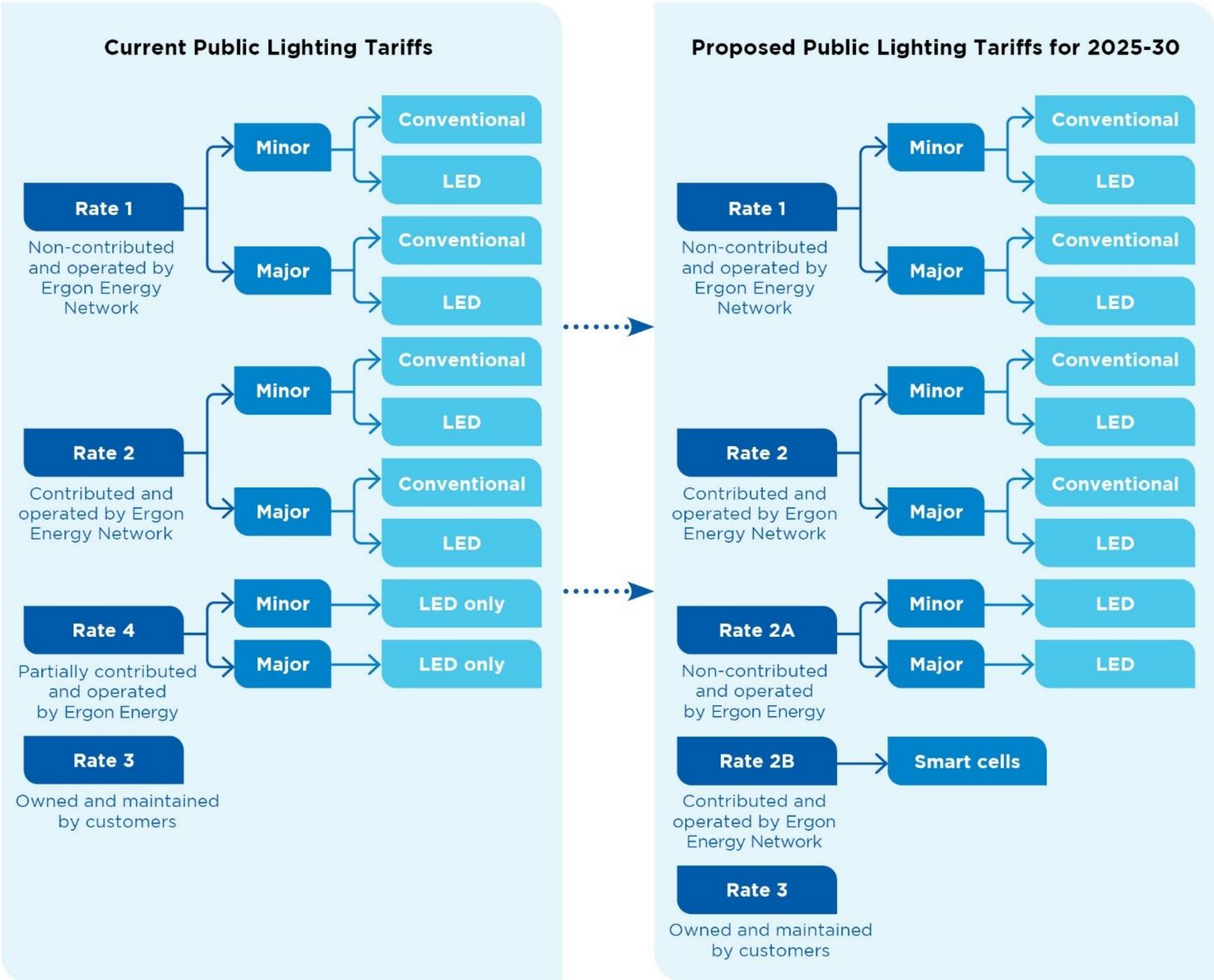
- Rate 2A to reflect Ergon Energy Network's funding of the capital costs of the conversion of the Rate 2 conventional assets to LED assets - this tariff will recover the capex and opex charges through the ACS public lighting charges, and
- Rate 2B to reflect the introduction of smart control devices - this tariff recovers the cost of the Data Management System, user interface, set up digital costs and costs associated with the replacement of defective assets.

On 1 July 2025 the existing Rate 4 assets will be reassigned to a Rate 2 LED tariff and the customer will no longer be charged the residual value of the non-contributed public lighting infrastructure.

The proposed changes to our public lighting tariffs are set out in Figure 57.

[28] Contributed assets are funded by customers upfront, not by Ergon Energy Network.

Figure 57: Current and proposed public lighting tariffs



Customers wishing to fund the capital cost of the conversion of their Rate 1 conventional lights to LED will have these assets assigned to the Rate 2 LED tariff, thereby benefitting from lower charges compared to Rate 4.

Details on indicative prices for our proposed public lighting tariffs are provided in Attachment 11.08.

11.2.3.3 Smart public lighting strategy

In response to customers' expectations and evolving needs, we will offer smart lighting capability to the public lighting fleet, utilising smart control devices (also known as 'smart cells'). Enabled by the LED technology, smart cells provide benefits that conventional photoelectric cells are unable to offer, such as dimming, trimming, adaptive lighting, constant light output and fault detection.

As part of the initial phase of our customer and stakeholder engagement, we considered three deployment and funding options for smart cells, namely:

- the user-pays approach (our preferred approach) whereby customers will be funding the upfront capital costs of the smart cells and gift the assets to Ergon Energy Network to operate and maintain
- full deployment of smart cells in line with the LED rollout, and
- do nothing until 2030.

Ultimately a measured transitional approach has been chosen by our customers that will see customers contribute to the cost of the installation and hardware upfront on an 'as requested' basis. Customers will then gift the contributed assets to Ergon Energy Network to operate and maintain. This approach is considered prudent as it will provide access to this technology while there is still regulatory uncertainty on its potential use as metering devices in the future, noting that the AEMC's draft determination on this matter, initially expected in October 2023, has been delayed to the end of February 2024.[29]

It also recognises that all councils are different, each with its own priorities and that some councils see benefits with the technology while others do not. The costs associated with the Control Management System, user interface, set up costs and replacement costs of faulty assets will be recovered through a new tariff, Rate 2B.

Smart cells will be offered from 1 July 2026 to give Ergon Energy Network sufficient time to develop standards and operating protocols, conduct a pilot, and establish procurement contracts with suppliers.

Further details are available in Attachment 11.10.

11.2.4 Our proposed expenditure

11.2.4.1 Operating expenditure

Ergon Energy Network has different maintenance activities consisting of cyclic replacements and in-service inspections. Each aspect has been reviewed and redesigned to suit the installation of LED lights (as LEDs require less frequent site inspections compared to conventional lights).

Key items considered when developing our proposed opex strategy are:

- night road patrol program
- pole inspection program, and
- in-service condition assessment – structural and electrical.

In recognition of the particular maintenance requirements associated with each technology, we have developed a maintenance strategy that reflects the estimated efficiencies that can be attributed to the legacy conventional and LED lights.

Based on the 2022-23 operating costs, the forecast opex is lower for the LED assets compared to conventional lights for the upcoming regulatory period (refer to Table 81). This lower opex is the result of:

- the exclusion of material costs as the entire LED luminaires, when faulty, will get replaced, which are categorised as capex, and

[29] Refer to AEMC's *Unlocking CER Benefits through Flexible Trading* rule change.

- an efficiency factor to reflect the estimated reduction in maintenance requirements for the newly installed LED lights.

The full LED deployment strategy by 30 June 2030 provides significant savings that will ultimately filter through to customer charges.

Table 81: Forecast public lighting opex ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
LED	5.5	6.7	7.6	8.4	9.4	**37.7**
Conventional	5.3	3.7	2.4	1.3	-	**12.7**
Total Opex[1]	**10.8**	**10.4**	**10.0**	**9.7**	**9.4**	**50.3**

Note 1: Totals may not add due to rounding.

11.2.4.2 Capital expenditure

The forecast capex required to execute our public lighting strategy for both Rate 1 and Rate 2 assets for the 2025-30 regulatory control period is forecast to be $80.6 million, compared to $94.9 million in net capex in the previous period. The forecast capex for LED lights is provided in Table 82.

Table 82: Forecast public lighting capex for LED lights ($m, real 2024-25)

	Future Period					
$m, real 2024-25	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Rate 1	9.7	9.8	9.9	10.0	10.1	**49.5**
Rate 2A	6.2	6.2	6.2	6.2	6.2	**31.1**
Total Capex[1]	**15.9**	**16.0**	**16.1**	**16.2**	**16.4**	**80.6**

Note 1: Totals may not add due to rounding.

It should be noted that Ergon Energy Network does not propose any new capex for conventional assets for the 2025-30 regulatory control period as these assets will be replaced with LED luminaires.

11.2.5 Our proposed public lighting revenue

We have used a limited building block approach to determine the ARR.

Consistent with our proposal to have separate tariffs for LEDs, we have prepared two asset bases within the PTRM:

- a conventional public lighting asset base covering the conventional asset revenue stream used to calculate the conventional public lighting tariffs, and
- a LED public lighting asset base covering the LED revenue stream, used to calculate the LED public lighting tariffs.

We have applied the same rate of return for public lighting services as for our SCS and have adopted the AER's PTRM straight-line depreciation. The tax allowance for public lighting is spread equally across both conventional and LED asset bases.

For the forecast opex, we have adopted a top-down approach based on the base-step-trend methodology similar to that used for SCS. It uses the 2022-23 actual opex figures (inclusive of oncosts and overheads) as the basis and trends the opex levels to 2030 using escalation factors and efficiency factors to reflect the lower maintenance requirements associated with the LED technology.

Our total forecast public lighting revenue for the 2025-30 regulatory control period is provided in Table 83 for conventional lights and Table 84 for LED lights.

Table 83: Forecast public lighting revenue for conventional lights ($m, nominal)

	Future Period					
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Return on capital	5.7	5.4	5.1	4.7	4.3	**25.3**
Depreciation	6.1	6.4	6.7	6.9	7.2	**33.3**
Opex	5.5	3.9	2.6	1.5	-	**13.4**
Annual revenue[1]	**17.3**	**15.7**	**14.4**	**13.1**	**11.5**	**72.0**

Note 1: Totals may not add due to rounding.

Table 84: Forecast public lighting revenue for LED lights ($m, nominal)

	Future Period					
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**Total[1]**
Return on capital	1.4	2.3	3.3	4.4	5.4	**16.8**
Depreciation	1.2	1.9	2.6	3.3	4.1	**13.1**
Opex	5.6	7.1	8.3	9.4	10.8	**41.2**
Annual revenue[1]	**8.2**	**11.3**	**14.2**	**17.1**	**20.4**	**71.2**

Note 1: Totals may not add due to rounding.

11.2.6 Our proposed public lighting tariffs and charges

In line with the price cap control mechanism applicable to ACS, we have developed indicative prices based on a dollar per asset per day charging approach. These indicative annual prices are included in Attachment 11.08.

Further details on the public lighting tariffs, tariff assignment and compliance with the price control mechanism can be found our 2025-30 Tariff Structure Statement.

11.2.7 How this differs from our Draft Plan

The main changes from the Draft Plan are:

- **update to opex** - as part of customer engagement and for this submission, we adopted a top-down approach based on the base-step-trend methodology similar to that used for SCS. It uses the 2022-23 actual opex figures (inclusive of oncosts and overheads) as the basis and trends the opex levels to 2030 using escalation factors and efficiency factors to reflect the lower maintenance requirements associated with the LED technology. Since the Draft Plan, we have adjusted our forecast opex by $7.5 million or 15.9 per cent to reflect the most recent update in our overheads and oncosts, as well as an update in consumer price index (CPI)

- **update to the WACC** - for the Draft Plan we used a nominal WACC of 7.22 per cent to develop our forecast capex. Due to updated inputs, the WACC is now 7.94 per cent, which has had an impact of 2 per cent on our forecast total return on capital to be recovered in the 2025-30 regulatory control period, and
- **changes to public lighting tariffs** - as noted above, we have developed a new tariff for smart cells to be offered from 1 July 2026. This new tariff, Rate 2B, will allow us to recover the set-up costs, central management system and costs associated with the replacement of faulty or end-of-life assets. The indicative 2025-30 charges for tariff Rate 2B are included in our Tariff Structure Statement.

11.2.8 Delivering for our customers

In line with our customers' expectations and specific requirements, our proposed 2025-30 public lighting strategy is grounded in our commitment to providing responsive, cost-effective, more environmentally-friendly, reliable and intelligent public lighting services for the future. Our smart lighting solutions offer innovation and potential benefits beyond those related to just traditional public lighting.

11.3 Ancillary services

11.3.1 Overview of ancillary services

Ancillary services are non-routine services provided to individual customers as requested. These services do not form part of the suite of common distribution services in recognition of the fact that not all customers request or require them.

Examples of ancillary services include:

- temporary disconnections and reconnections
- supply abolishment
- re-arrangement of connection assets, and
- meter tests.

Ancillary services fall under the ACS service classification in the F&A determination by the AER. Ancillary services are either charged on a fee or quotation basis, depending on the nature of the service.

Due to their relative standardised nature, fee-based services are charged using fixed prices based on standardised service assumptions.

Fee-based services fall under a price cap control mechanism. This means that the AER sets the maximum efficient prices that Ergon Energy Network is permitted to charge for providing the services.

The costs of providing these services are recovered through tariffs and charges billed to electricity retailers who in turn pass on the charge to end customers.

11.3.2 Fee-based pricing methodology

The charges for fee-based services are set in accordance with specified service assumptions due to the standardised nature of the services.

In the first year of a regulatory control period, the prices for fee-based services are determined using a cost build-up approach based on the following formula:

Price = Labour + Contractor services + Materials

Where:

- **Labour** consists of all labour costs directly incurred in the provision of the service which may include, but is not limited to, labour oncosts, fleet oncosts and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, the time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service
- **Contractor services** reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, e.g. permits for road closures or footpath access, are passed on to the customer, and
- **Materials** reflects the cost of materials directly incurred in the provision of the service, material storage and logistics oncosts and overheads.

Prices in subsequent years of the regulatory control period will be based on the cost build-up developed for 2025-26, escalated using CPI minus X factors determined by the AER.

11.3.3 Our approach to amendments to fee-based services

For the forthcoming 2025-30 regulatory control period we are proposing several incremental changes to our fee-based services. In addition to updating our forecast labour rates and overheads, we have conducted a thorough review of our services and service dimensions, such as travel time, time to complete a job and number of crew members required to perform a task. The proposed changes are summarised below:

- **Consolidation of services**

  At recent officer-level meetings with the AER, the AER requested that Ergon Energy Network consider consolidating its ancillary services as part of its forthcoming 2025-30 Regulatory Proposal. Currently, the number of core ancillary services comprises of just 47 services but when considering the number of permutations, the number of services increases to 310.

  In response to the AER’s expectation, we are proposing to discontinue several services which have had little or no uptake for the past three years. For example, we are proposing to remove the ‘anytime’ permutations.[30] We are also proposing to discontinue several ‘after hours’ services which have had little to no uptake. If an after hours service is requested and is no longer available, we will charge for the service at the ‘business hour’ price.

  In addition to the above proposed changes, we are also proposing to amalgamate the feeder types (Urban/Short rural and Long rural/Isolated) into a single service permutation.

  Following our review of services, our service offering will be reduced to 137 service permutations.

[30] The ‘anytime’ permutation was developed for urgent job requests raised after the 1pm cut-off (but prior to 2.30pm). After hours fees apply to anytime service requests.

- **Travel time**

  Following the amalgamation of the feeder types noted above, travel times to sites will be determined on an average basis regardless of their location, and will add a modest increase of three minutes to travel time for services conducted on urban and short-rural feeders.

- **Contractor costs**

  In 2023, we finalised new contract extensions with our existing external service providers which met our performance standards, particularly around safety and quality. The shortage of reputable and qualified external service providers in the market, coupled with a decline in meter reading services due to the uptake of smart meters, has meant that it is commercially appropriate for us to leverage contract extensions with our existing service providers rather than return to an open market in an environment where the likelihood of growth in this space is extremely low. The lack of opportunities in a declining market has led to substantial increases in contracted rates being negotiated for the forthcoming regulatory control period.

  Furthermore, following a series of recent incidents, we have raised our health and safety requirements, mandating that certain services be conducted by a two-person crew, rather than a single person. This has had a flow-on impact on the negotiated schedule of rates with our contractors.

  Finally, other cost increases are related to some services being historically priced at an unsustainably low level and warranted an uplift adjustment for our service providers to continue offering these services.

  Despite the forthcoming increases in contractor costs, the use of external resources remains the most cost-effective option for Ergon Energy Network and our customers.

- **New standardised AER model**

  The AER has developed a standardised ancillary services (ANS) model to improve consistency across the NEM and to streamline the resources and consultation required on ancillary services modelling. It is anticipated that this consistency will also provide stakeholders, such as retailers and end customers, with greater scope to engage with DNSPs in developing their proposals.

  We have used the ANS model for the first time in our 2025-30 Regulatory Proposal. The use of this model means that we have had to adjust our overheads so that they would align with the structure of the model. These adjustments to the overheads required that we develop weighted average rates outside the model which would ultimately reconcile with our CAM.

11.3.4 Our indicative prices for fee-based services

Indicative prices for fee-based services for the 2025-30 regulatory control period are calculated in the AER's ANS model Attachment 11.06 and set out in Attachment 11.08.

11.3.5 Quoted services

Prices for quoted services are determined at the time the customer makes an enquiry and therefore reflect the individual nature and scope of the requested service which cannot be known in advance. The charges for the following customer-requested services will be determined on a quoted basis:

- connection application management services
- enhanced connection services, and
- auxiliary public lighting services.

Unlike previous Regulatory Proposals, we are proposing to use labour rates specific to quoted services for the 2025-30 regulatory control period. As noted above, fee-based services apply weighted average overheads to the base labour rate to accommodate the constraints of the new model. In contrast, the overheads to be applied to the base labour rates specific to quoted services have not been adjusted. This approach will ensure we recover our actual costs when developing prices on a quoted basis. Our proposed labour rates and full list of quoted services are included in the ANS model in Attachment 11.06.

In line with the F&A, we propose to apply a margin to our quoted services. We note that the AER has proposed a uniform 6 per cent margin in the draft decisions for the New South Wales, Australian Capital Territory, Tasmania and Northern Territory distributors. We consider that a fixed margin strikes the right balance between minimising administrative burden while promoting competitive neutrality.

As noted in section 11.4.2 below, from 1 July 2025, Ergon Energy Network will no longer offer the installation of new security lights as a service. Installation of new security lights is currently charged on a quoted basis.

Further details on the formula used for quoting prices are provided in our Tariff Structure Statement and our proposed list of quoted services is in Attachment 11.06.

11.4 Security lighting

11.4.1 Overview

Security lighting services generally involve installation, operation, maintenance and replacement of lighting equipment which is typically mounted to our distribution network poles and structures.

Until the commencement of the 2020-25 regulatory control period security lighting services have been provided as an unregulated service with Ergon Energy Network having full discretion in relation to the pricing methodology and charges applicable for this service.

With security lighting services becoming ACS from 1 July 2020, we decided to split the one-off installation charge from the on-going maintenance, operation and replacement charge and proposed to charge for this service on an as quoted basis. The intention was to assist Ergon Energy Network with the identification of these costs and prevent further cost under-recovery.

11.4.2 Changes to security lighting services

As part of our submission to the AER's F&A process, we proposed to cease providing and installing security lights for new customers in the 2025–30 regulatory control period, but to continue to maintain and operate security lights for existing customers until they transition to alternative solutions. In its determination the AER agreed with the proposed change, noting it reflected the changing requirements of the market and does not appear to have a negative impact on consumers. It also confirmed its classification of security lighting as an ACS.

11.4.3 Tariffs for security lighting services

Other than new security lighting installations no longer being offered from 1 July 2025, we do not propose any other changes to our security lighting services.

The proposed security lighting tariffs for the 2025-30 regulatory control period are provided in Table 85.

Table 85: Security lighting tariffs for 2025-30

Tariff grouping	Tariffs	Description
Maintenance, operation and replacement	Small LED	W70, W100
	Medium LED	W200
	Small conventional	High Pressure Sodium and Metal Hallide 150W
	Medium conventional	High Pressure Sodium, Metal Hallide or Mercury Vapour 250W
	Large conventional	High Pressure Sodium, Metal Hallide or Mercury Vapour 400W
Energy use	Unmetered supply	Charges vary depending on the light type and size Usage based on actual wattage according to AEMO

Further discussion on our proposed security lighting tariffs and compliance with the price control mechanism can be found in our Tariff Structure Statement.

11.4.4 Our indicative prices for security lighting services

It is proposed that the indicative prices for the 2025-30 regulatory control period should be based on the previous year's prices adjusted by CPI minus X. This is considered to be a simple and pragmatic approach. Given the minimal changes in some of the underlying costs and very low volumes, we believe that a cost build up approach for the first year of the regulatory control period is not warranted. The X factor is ultimately determined by the AER. However, we propose to use the 2025-26 labour escalation rate as this aligns with the methodology previously used to set prices for security lighting services from 2020-21 to 2024-25.

The proposed indicative prices for our security lighting tariffs for the 2025-30 regulatory control period are developed in Attachment 11.07 and set out in Attachment 11.08.

11.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
ACS Public Lighting Capex and Opex forecasting model 2025-30	11.01	Ergon - 11.01 – ACS Public lighting capex and opex forecasting model 2025-30 – January 2024 - public
ACS Public Lighting Pricing Model	11.02	Ergon – 11.02 – ACS Public lighting pricing model – January 2024 - public
ACS Public Lighting RFM Model	11.03	Ergon – 11.03 – ACS Public lighting RFM 2025-30 – January 2024 - public
ACS Public Lighting PTRM Model	11.04	Ergon – 11.04 – ACS Public lighting PTRM 2025-30 – January 2024 - public
ACS Smart Control Pricing Model	11.05	Ergon – 11.05 – ACS Smart control pricing model – January 2024 - public
ACS Ancillary Services Model	11.06	Ergon – 11.06 – ACS Ancillary services model – January 2024 – public Ergon – 11.06 – ACS Ancillary services model – January 2024 – confidential
ACS Security Lighting Model	11.07	Ergon – 11.07 – ACS Security lighting pricing model – January 2024 - public
ACS Price Schedule for 2025-30	11.08	Ergon – 11.08 – ACS Price schedule 2025-30 – January 2024 - public
ACS Explanatory Statement	11.09	Ergon – 11.09 – ACS Explanatory Statement – January 2024 - public
Smart Public Lighting Strategy	11.10	Ergon – 11.10 – Ironbark Smart Public Lighting Strategy – November 2023 - public
ACS ANS Fee-based services comparison	11.11	Ergon - 11.11 - ACS ANS Fee-based services comparison – January 2024 – public Ergon - 11.11 - ACS ANS Fee-based services comparison - January 2024 - confidential

12.
Other Regulatory Matters

Key messages:

- We support the F&A position to maintain the current SCS classification for common distribution services, network ancillary services and connection services. We also support the addition of regulated SAPS and rectification of simple customer faults under the common distribution services grouping.
- In accordance with AER guidance and customer feedback, we are proposing that legacy metering services should be reclassified as SCS, and as such propose amendments to the SCS control formulae.
- We support the F&A decision to maintain the current control mechanisms, being a revenue cap for SCS and a price cap for ACS.
- The following jurisdictional schemes will apply for 2025-30: the Solar Bonus Scheme; Energy Industry Levy; and Electrical Safety Office Levy.
- We agree with the AER's decision not to classify any of our services as negotiated distribution services. Notwithstanding, in accordance with the NER, we submit a negotiating framework to apply in the event that the AER departs from this decision.
- In addition to the prescribed pass through events set out in the NER, we propose the following nominated pass through events: an insurance coverage event; an insurer's credit risk event; a terrorism event; and a natural disaster event.
- We do not propose any contingent projects for this regulatory control period.
- We have addressed the requirements of the AER's Confidentiality Guideline as to the matters for which we are claiming confidentiality.
- Our directors have provided a certification statement for our key assumptions for capex and opex.
- Our Chief Executive Officer has made a statutory declaration attesting to the information provided in our response to the AER's RIN.

12.1 Overview

This chapter addresses a number of regulatory matters, including application of the AER’s proposed approach to the classification of distribution services, incentive schemes and control mechanisms for ACS and SCS. It also covers other regulatory requirements, including the requirement for a negotiating framework, jurisdictional schemes, nominated pass through events and contingent projects, and addresses our approach to confidentiality and assurance, and certification requirements.

12.2 Classification of Services

Service classification determines which of our distribution services will be regulated by the AER and how the costs of the regulated services will be recovered from customers. The NER specify that a Regulatory Proposal must contain, amongst other things, a service classification proposal[31]

[31] Clause 6.8.2(c)(1) of the NER.

and the service classification must be as set out in the F&A unless the AER considers that a material change in circumstances justifies departing from the classification as set out in the F&A.[32]

On 3 July 2023, the AER published the Final F&A for the 2025-30 regulatory control period. We largely accept the service classification positions in the Final F&A. Attachment 12.01 provides the full service listing for the 2025-30 regulatory control period. We summarise our proposals below.

12.2.1 Common distribution services

We support the F&A position to maintain the current SCS classification for common distribution services and the addition of the following activities in the service grouping:

- regulated SAPS due to the *National Electricity Amendment (Regulated Stand-Alone Power Systems) Rule* 2022
- rectification of simple customer faults, which allow us to rectify simple faults located behind the meter that are discovered by our crews when investigating customer outages, and
- customer export services following the *National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule* 2021. This activity is recognised but not separately listed.

12.2.2 Network ancillary services

We support the F&A position to maintain the current SCS classification for network ancillary services. We further accept the amendment to the security lighting activity to recognise that we will cease to provide security lighting services to new customers but will continue to operate and maintain existing security lights.

12.2.3 Connection services

We support the F&A position to maintain the current service classifications. These include SCS for small customer connections, network extensions and augmentation, and ACS for large customer premises connections, connection application and management services and enhanced connection services.

12.2.4 Metering services

On 30 August 2023, the AEMC published its final report on the *Metering Services Review*. Consistent with the guidance provided by the AER in the F&A, we propose to reclassify legacy metering services as SCS. The F&A maintained an ACS classification for legacy metering services but expected us to depart from this classification after the completion of the AEMC's review. The AER considered that the AEMC's review would constitute a material change in circumstances. We support this view.

We have engaged with our RRG and customers, and they broadly support the reclassification to allow us to spread the recovery of legacy metering costs to all customers and prevent the burden of legacy metering costs falling mostly on our most vulnerable customers.

Chapter 10 discusses our proposal to reclassify legacy metering services to SCS in more detail.

[32] Clause 6.12.3(b) of the NER.

12.3 Control mechanisms

The NER specify that a distribution determination must impose controls over the prices of direct control services, revenue to be derived from the direct control services, or both.[33] The NER also specify that the form and formulae of the control mechanisms must be set out in the F&A.[34] The AER may only depart from the formulae set out in the F&A if there is a material change in circumstances.

We support the F&A decision to maintain the current control mechanisms, being a revenue cap for SCS and a price cap for ACS. However, as discussed below, we propose a departure from the control formulae for SCS provided in the F&A.

12.3.1 Standard control services formulae

As discussed in section 10.3, we propose to depart from the F&A service classification for legacy metering services as the AEMC's final report on the *Metering Services Review* constitutes a material change in circumstances. Consequently, the control formulae for SCS provided in the F&A require amendments. We have adopted the revised control formulae in Table 86 for SCS. These formulae are consistent with the AER's October 2023 guidance note on legacy metering services provided to the New South Wales, Australian Capital Territory, Tasmania and Northern Territory distributors. The formulae maintain transparency by separating legacy metering revenue from the main SCS.

Table 86: SCS control formulae

	Equation	Where
1.	$TAR_t \geq \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_t^{ij}$	$i = 1, \dots, n$ $j = 1, \dots, m$ $t = 1,2,3,4,5$
2.	$TAR_t = TAR_t^{SCS} + TAR_t^{M}$	$t = 1,2,3,4,5$
3.	$TAR_t^{SCS} = AAR_t^{SCS} + I_t^{SCS} + B_t^{SCS} + C_t^{SCS}$	$t = 1,2,3,4,5$
4.	$AAR_t^{SCS} = AR_t^{SCS}$	$t = 1$
5.	$AAR_t^{SCS} = AAR_{t-1}^{SCS} \times (1 + \Delta CPI_t) \times (1 - X_t^{SCS})$	$t = 2,3,4,5$
6.	$TAR_t^{M} = AAR_t^{M} + I_t^{M} + B_t^{M} + C_t^{M}$	$t = 1,2,3,4,5$
7.	$AAR_t^{M} = AR_t^{M}$	$t = 1$
8.	$AAR_t^{M} = AAR_{t-1}^{M} \times (1 + \Delta CPI_t) \times (1 - X_t^{M})$	$t = 2,3,4,5$
9.	$B_t = b_t + A_t$	$t = 1,2,3,4,5$
10.	$b_t = -O_t \times (1 + WACC_t)^{0.5}$	$t = 1,2,3,4,5$
11.	$A_t = a_{t-2}^{1} \times (1 + WACC_{t-1}) \times (1 + WACC_t) + a_{t-1}^{2} \times (1 + WACC_t) + a_t^{3}$	$t = 1,2,3,4,5$
12.	$WACC_t = (1 + rvWACC_t) \times (1 + CPI_t) - 1$	$t = 1,2,3,4,5$

[33] Clause 6.2.5(a) of the NER.

[34] Clauses 6.12.3(c) and 6.12.3(c1) of the NER.

Where:

Variable	Equation
t	The regulatory year with $t = 1$ being the 2025-26 financial year.
TAR_t	The total annual revenue for year t, calculated as per formula 2 above.
TAR_t^{SCS}	The total annual revenue for main SCS for year t, calculated as per formula 3 above.
TAR_t^{M}	The total annual revenue for metering for year t, calculated as per formula 6 above.
p_t^{ij}	The price of component 'j' of tariff 'i' for year t.
q_t^{ij}	The forecast quantity of component 'j' of tariff 'i' for year t.
AR_t^{SCS}	The annual smoothed revenue requirement in the main SCS PTRM for year t.
AR_t^{M}	The annual smoothed revenue requirement in the metering SCS PTRM for year t.
AAR_t^{SCS}	The adjusted annual smoothed revenue requirement for main SCS for year t, calculated as per formulae 4 and 5 above.
AAR_t^{M}	The adjusted annual smoothed revenue requirement for metering SCS for year t, calculated as per formulae 7 and 8 above.
I_t^{SCS}	The sum of incentive scheme adjustments for year t. Where applicable, incorporates revenue adjustments relating to the outcomes of: • the STPIS (S-factor) in relation to regulatory year t-2 • the DMIS in relation to regulatory year t-2 • the DMIAM relating to the 2019–24 regulatory control period to be applied in regulatory year t=2 only • the CSIS (H-factor) in relation to regulatory year t-2 • the ESIS (E-factor) in relation to the regulatory year t-2 • any other related incentive schemes as applicable that are to be applied in year t.
B_t^{SCS}	The sum of annual adjustment factors to balance the unders and overs account for year t, calculated as per formula 9 above. It includes: • the true-up of any under or over recovery of actual revenue (b-factor) collected through distribution use of system (DUoS) charges calculated using the method outlined in formula 7 • Any other bespoke adjustments the AER deems necessary (A-factor). These include but are not limited to residuals of jurisdictional scheme amounts upon cessation, applicable licence fee payments, or other true-ups not provided for elsewhere. These adjustments will apply the time value of money where appropriate, calculated as per formula 11 above.
C_t^{SCS}	The approved pass through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end of period adjustments for year t.
I_t^{M}	The sum of incentive scheme adjustments for metering services for year t. Currently no incentive schemes apply.
B_t^{M}	The sum of annual adjustment factors to balance the unders and overs account for year t, calculated as per formula 9 above. It includes: • the true-up of any under or over recovery of actual revenue (b-factor) collected through metering services charges calculated using the method outlined in formula 7 • any other bespoke adjustments the AER deems necessary (A-factor). These include but are not limited to the true-up of opex explicitly related to variances from forecast metering volumes, or other true-ups not provided for elsewhere. These adjustments will apply the time value of money where appropriate, calculated as per formula 11 above.
C_t^{M}	The approved pass through amounts (positive or negative) for metering services for year t, as determined by the AER. It will also include any annual or end of period adjustments for metering services for year t.

Variable	Equation
ΔCPI	The annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities[35] from December in year t–2 to December in year t–1. For example, for the 2024–25 year, t–2 is December 2022 and t–1 is December 2023.
X_t^{SCS}	The X-factor in year t, incorporating annual adjustments to the main SCS PTRM for the trailing cost of debt.
X_t^M	The X-factor in year t, incorporating annual adjustments to the main SCS PTRM for the trailing cost of debt.
b_t	The true-up for the balance of the respective unders and overs account in year t, calculated as per formula 10 above.
O_t	the opening balance of the respective unders and overs account in year t as calculated by the method in Appendix A of the control mechanisms draft decision.
$WACC_t$	the approved weighted average cost of capital (WACC) used in regulatory year t in the DUoS unders and overs account in Appendix A. The WACC is updated annually to apply actual inflation, calculated as per formula 12 above. It also applied to true-up mechanisms to adjust for the time value of money.
A_t	the sum of bespoke adjustments, including the application of the time value of money where appropriate, calculated as per formula 11 above.
a_t^1	the bespoke adjustment '1' for year t. Formula 11 above demonstrates the application of the time value of money for different bespoke adjustments relating to different regulatory years.
$rvWACC_t$	the real vanilla WACC provided in the annually updated PTRM for year t.

12.3.2 Alternative control service formulae

We support the control formulae provided in the F&A.

12.3.3 Side constraint mechanism

The side constraint mechanism is provided in the NER and serves to limit the amount of revenue that can be recovered from a tariff class relative to the revenue recovered from the same tariff class in the previous year. The side constraint formulae are provided in the distribution determination and the annual pricing proposal must demonstrate compliance with the mechanism. The mechanism applies to SCS only.

In November 2022, the AER published its final position paper on the application of the side constraint mechanism as part of the review into improving the annual pricing approval process for distributors. The final position developed a standardised side constraint mechanism that will apply in our 2025-30 distribution determination. We are supportive of the AER's amendments to the mechanism that will apply in the 2025-30 regulatory control period.

12.3.4 Jurisdictional scheme amounts

Jurisdictional scheme amounts relate to the recovery of costs associated with specific obligations placed on DNSPs by State Governments. The NER specify that the distribution determination must set out how the DNSP is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

[35] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

In Queensland, the following jurisdictional schemes will apply in the 2025-30 Regulatory Proposals:

- **the Solar Bonus Scheme** – this scheme obligates Ergon Energy Network to make feed-in-tariff payments for energy supplied into our distribution network from specific micro-embedded generators. This scheme is expected to end on 30 June 2028
- **the Energy Industry Levy** – this levy covers a proportion of the Queensland Government's funding commitments to NEM regulation costs as well as other national energy policy costs, and
- **the Queensland Electrical Safety Office Levy** - on 31 March 2023, the AER determined that the Queensland Electrical Safety Office Levy is a jurisdictional scheme as it meets the jurisdictional scheme eligibility criteria under the NER and that the determination will take effect from 1 July 2025.[36] Consequently, we have removed the forecast expenditure associated with the Electrical Safety Office Levy from our opex forecast (refer to section 6.3.2).

In accordance with the NER requirements, we propose to specify the jurisdictional scheme amounts applicable in the relevant regulatory year in our annual pricing proposals.

12.3.5 Designated pricing proposal charges

Designated pricing proposal charges are transmission related costs, including transmission use of system charges, avoided transmission use of system charges paid to eligible embedded generators and payments to other distributors for supply of distribution services.

The NER stipulate that distribution determinations must set out how the DNSP is to report to the AER on its recovery of designated pricing proposal changes for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.[37]

In accordance with the NER requirements, we propose to specify the following in our annual pricing proposals:

- payments:
  - regulated transmission charges paid to transmission networks
  - avoided transmission charges paid to eligible embedded generators
  - payments made to other DNSPs for use of their network
- receipts:
  - payments received from network users
  - payments received from other DNSPs
  - adjustments for over/under recovery, and
- difference between receipts and payments.

[36] AER Determination on jurisdictional scheme application in relation to the *Electrical Safety Act* 2002 (Qld), published 3 April 2023.
[37] Clause 6.12.1(19) of the NER.

12.4 Negotiating framework

Ergon Energy Network is required to prepare and submit a negotiating framework with this Regulatory Proposal for approval by the AER.[38] The negotiating framework will apply to negotiations for any distribution service provided by Ergon Energy Network that the AER has determined does not require direct control, allowing the terms and conditions for provision of the service, including price, to be set by the parties to the negotiation. It sets out the procedure to be followed by Ergon Energy Network and any customer who wishes to receive a negotiated distribution service.

The AER's F&A has not classified any of Ergon Energy Network's services as negotiated distribution services for the 2025-30 regulatory control period. We agree with the AER's determination that none of our distribution services are suited to being classified as a negotiated distribution service.

Notwithstanding this decision, and in accordance with the requirements of the NER, Ergon Energy Network's proposed negotiating framework for the 2025-30 regulatory control period is provided in Attachment 12.02.

12.5 Pass through events

The cost pass through mechanism allows Ergon Energy Network to seek approval to recover a material increase in costs incurred, or to pass on a significant cost saving made, because of an event that impacts the provision of direct control services during the regulatory control period. It typically applies to high-impact events that are unpredictable and outside the reasonable control of Ergon Energy Network to prevent or mitigate.

As the additional costs arising from such events have not been factored into our ARR, the mechanism allows the AER to approve a price adjustment for certain pre-defined events that meet the cost pass through criteria. As part of its assessment, the AER will ensure that any proposed cost increase (or decrease) is efficient and that the impact on prices for customers is no more than necessary.

The NER allows all DNSPs to apply for a cost pass through for the following prescribed events:

- a regulatory change event
- a service standard event
- a tax change event, and
- a retailer insolvency event.[39]

In addition, a DNSP may nominate additional pass through events in its Regulatory Proposal (nominated pass through events).[40] Ergon Energy Network is proposing the following nominated pass through events for the 2025-30 regulatory control period:

- insurance coverage event
- insurer credit risk event
- terrorism event, and
- natural disaster event.

[38] Clause 6.8.2(c)(5) of the NER.
[39] Clause 6.6.1(a1) of the NER.
[40] Clause 6.6.1(a1)(5) of the NER.

These events are consistent with the nominated pass through events approved by the AER in the current 2020-25 distribution determination for Ergon Energy Network and with recent decisions for other network service providers.

Table 87 outlines our proposed nominated pass through events and their respective definitions for the 2025-30 regulatory control period.

Table 87: Proposed nominated pass through events for the 2025-30 regulatory control period

Pass through event	Definition
Insurance coverage	An insurance coverage event occurs if: 1. Ergon Energy Network: a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies, or b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances, and 2. Ergon Energy Network incurs costs: a) beyond a relevant policy limit for that policy or set of insurance policies b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances, and 3. The costs referred to in paragraph 2 above materially increase the costs to Ergon Energy Network in providing direct control services. For the purposes of this insurance coverage event: 4. 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of Ergon Energy Network, where those movements mean that it is no longer possible for Ergon Energy Network to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies 5. 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had: • the limit not been exhausted, or • those costs not been unrecoverable due to changed circumstances 6. a relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which Ergon Energy Network was regulated, and 7. Ergon Energy Network will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of Ergon Energy Network in relation to any aspect of Ergon Energy Network's network or business, and 8. Ergon Energy Network will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of Ergon Energy Network relation to any aspect of Ergon Energy Network's network or business. Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(j), the AER will have regard to: (i) the relevant insurance policy or set of insurance policies for the event (ii) the level of insurance that an efficient and prudent DNSP would obtain, or would have sought to obtain, in respect of the event (iii) any information provided by Ergon Energy Network to the AER about Ergon Energy Network's actions and processes, and (iv) any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.

Pass through event	Definition
Insurer credit risk	An insurer credit risk event occurs if an insurer of Ergon Energy Network becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Ergon Energy Network: a) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy, or b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer. Note: in assessing an insurer credit risk event pass through application, the AER will have regard to, amongst other things: (i) Ergon Energy Network attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer’s track record, size, credit rating and reputation, and (ii) in the event that a claim would have been covered by the insolvent insurer's policy, whether Ergon Energy Network had reasonable opportunity to insure the risk with a different provider.
Natural disaster	Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2025-30 regulatory control period that changes the costs to Ergon Energy Network in providing direct control services, provided the cyclone, fire, flood, earthquake or other event was: a) a consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or b) not a consequence of any other act or omission of the service provider. Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things: (i) whether Ergon Energy Network has insurance against the event, (ii) the level of insurance that an efficient and prudent network service provider would obtain in respect of the event.
Terrorism	Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: 1. from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and 2. changes the costs to Ergon Energy Network in providing direct control services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: (i) whether Ergon Energy Network has insurance against the event (ii) the level of insurance that an efficient and prudent network service provider would obtain in respect of the event, and (iii) whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

In proposing these four nominated pass through events, Ergon Energy Network has had regard to the nominated pass through event considerations defined in Chapter 10 of the NER and we consider that:

- the events are not covered by a category of pass through event specified in the NER
- the nature and type of the events can be clearly identified at the time the determination is made, and

- while Ergon Energy Network could act to:
  - reduce the likelihood of such events from occurring or mitigate the cost impacts, and
  - insure or self-insure against the event,

  expenditure beyond a certain level to eliminate these risks is not likely to be prudent or efficient.

We propose that the prescribed and nominated pass through events set out above will apply to both SCS and ACS. We consider that this is consistent with the NER, which refers to the provision of direct control services (i.e. both SCS and ACS) in relation to pass through events.

12.6 Contingent projects

Under the NER, a Regulatory Proposal may include a proposal for a project to be determined by the AER as a contingent project for the regulatory control period.[41] The contingent projects mechanism is intended to apply where there is uncertainty as to the need for or timing of a specific network project during the regulatory control period. It would allow Ergon Energy Network to apply to the AER to adjust our revenue allowance where a pre-defined trigger event for the contingent project has occurred.

Ergon Energy Network has not identified any contingent projects for the 2025-30 regulatory control period.

12.7 Confidential information

The NER require that Ergon Energy Network must identify the parts of its Regulatory Proposal that are confidential and provide details in accordance with the AER's *Distribution Confidentiality Guideline*.[42]

Accordingly, our Confidentiality template (Attachment 12.03) sets out the information provided as part of this Regulatory Proposal for which Ergon Energy Network is claiming confidentiality.

12.8 Governance, assurance and certifications

12.8.1 Certification statement

Ergon Energy Network's Directors are required to certify the key assumptions that underlie our capex and opex forecasts.[43] Our key assumptions are set out in the following sections of this Regulatory Proposal:

- capex assumptions are set out in section 5.2, and
- opex assumptions are set out in section 6.2.

Our certification statement is provided as Attachment 12.04 to this Regulatory Proposal.

[41] Clause 6.6A.1 of the NER.
[42] Clause 6.8.2(c)(6) of the NER.
[43] Schedules 6.1.1(5) and 6.1.2(6) of the NER.

12.8.2 Statutory declaration by Chief Executive Officer

The AER's Reset RIN requires an officer of Ergon Energy Network to make a statutory declaration attesting to the information provided in response to that notice.

The statutory declaration made by our Chief Executive Officer is provided as Attachment 12.05 to this Regulatory Proposal.

12.8.3 Compliance checklist

Ergon Energy Network has completed a compliance checklist which demonstrates how we have complied with the requirements of the NER and the RIN. This checklist is provided as Attachment 12.06.

12.9 Supporting documentation

The following documents support this chapter:

Document	Ref	File Name
Service classification	12.01	Ergon - 12.01 - Service classification - January 2024 - public
Negotiating framework 2025-30	12.02	Ergon - 12.02 - Negotiating framework 2025-30 - November 2023 - public
Confidentiality template	12.03	Ergon – 12.03 – Confidentiality template - pulbic
Key capex and opex assumptions certification	12.04	Ergon – 12.04 – Key capex and opex assumptions certification - pulic
Chief Executive Officer statutory declaration	12.05	Ergon – 12.05 – Chief Executive Officer statutory declaration - public
Compliance checklist	12.06	Ergon – 12.06 – Compliance checklist - public

13.
Glossary

Chapter 13: Glossary

Term	Meaning
$, nominal	These are nominal dollars of the day
$, real 2024-25	These are dollar terms as at 30 June 2025
2025-30 regulatory control period	The regulatory control period commencing 1 July 2025 and ending 30 June 2030
ABS	Australian Bureau of Statistics
ACS	Alternative control service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ANS	Ancillary services model
ARR	Annual revenue requirement
Augex	Augmentation capital expenditure
BEL	Basic export level
CAC	Connection asset customer
CAM	Cost allocation method
Capex	Capital expenditure
CBD	Central business district
CBRM	Condition Based Risk Management
CECV	Customer export curtailment value
CESS	Capital Expenditure Sharing Scheme
Connex	Connections capital expenditure
CPI	Consumer price index
Current regulatory control period or current period	The regulatory control period commencing 1 July 2020 and ending 30 June 2025
CSIS	Customer Service Incentive Scheme
DEBBS	ICT & Digital Enterprise Building Blocks
DER	Distributed energy resources
DMIA	Demand Management Incentive Allowance
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUoS	Distribution use of system
Dynamic connection	Dynamic connections will allow customers to access increased network capacity at times when the network is not constrained by receiving dynamic operating envelopes rather than setting static limits
Dynamic operating envelopes	Dynamic operating envelopes vary limits over time, based on the capacity or other capability of the network in near real time. This includes, for example, export and import limits at the local network or power system as a whole
EBSS	Efficiency Benefits Sharing Scheme
Energy Queensland	Energy Queensland Limited
ESIS	Export Service Incentive Scheme

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Term	Meaning
F&A	Framework and Approach
GWh	Gigawatt hours
IAP2	International Association of Public Participation
ICC	Individually calculated customer
ICT	Information and communications technology
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light emitting diode
LRMC	Long run marginal cost
LVDERMS	Low Voltage Distributed Energy Resource Management System
MSS	Minimum service standard
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2025 and ending 30 June 2030
NPV	Net present value
Opex	Operating and maintenance expenditure
PoE	Probability of exceedance
Previous regulatory control period or previous period	The regulatory control period commencing 1 July 2015 and ending 30 June 2020
PTRM	Post tax revenue model
PV	Photovoltaic (solar PV)
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Regulatory Proposal	Ergon Energy Network's Regulatory Proposal for the next regulatory control period submitted under clause 6.8 of the NER
Repex	Replacement capital expenditure
RFM	Roll forward model
RIN	Regulatory information notice
RIT-D	Regulatory Investment Test for Distribution
RRG	Reset Reference Group
SAC	Standard asset customer
SAPS	Stand-alone power system
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index

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Term	Meaning
SCADA	Supervisory control and data acquisition
SCS	Standard control service
STPIS	Service target performance incentive scheme
V	Volt
VCR	Value of customer reliability
WACC	Weighted average cost of capital

Part of Energy Queensland

Project team: RDP2025Connect@energyq.com.au

ergon.com.au

Ergon Energy Network
PO Box 1090
Townsville QLD 4810

2-23-0333