Energex
Revised Regulatory Proposal

2025-30

November 2024

energex

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

Energex 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.

Energex 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 South East Queensland in the most affordable way.

ABOUT THIS REVISED REGULATORY PROPOSAL

Energex Limited (Energex) 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 South East Queensland. We own, operate, and maintain the "poles and wires" that deliver power to 1.6 million homes and businesses from the New South Wales border in the south to Gympie in the north and west to the base of the Great Dividing Range.

To ensure Energex manages the electricity distribution network in South East Queensland efficiently, we are regulated under the National Electricity Law and the National Electricity Rules (NER) by a national regulator, the Australian Energy Regulator (AER). The AER is responsible for determining the maximum allowed revenue Energex can recover from customers for using its network for the next five-year regulatory control period commencing on 1 July 2025 and ending on 30 June 2030 (the 2025-30 regulatory control period).

On 31 January 2024, Energex submitted a Regulatory Proposal for the 2025-30 regulatory control period to the AER. Our Regulatory Proposal set out the amount of funding required to build, operate and maintain the electricity distribution network in South East Queensland and the revenue we intend to collect from our customers through distribution charges. Our Regulatory Proposal was accompanied by a plain-language overview of our proposal and a range of supporting documentation, including our proposed Tariff Structure Statement (TSS).

On 23 September 2024, the AER published its Draft Decision on Energex's electricity distribution determination for the 2025-30 regulatory control period. This is our Revised Regulatory Proposal in response to the AER's Draft Decision. We developed this Revised Regulatory Proposal in consultation with customers and stakeholders.

Our Revised Regulatory Proposal is structured as follows:

- **Executive Summary** - provides a high-level summary of our Revised Regulatory Proposal
- **Chapter 1: Context for our Revised Proposal** - provides background information on our network and operating environment
- **Chapter 2: Customer and Stakeholder Engagement** - outlines the engagement we have undertaken since we submitted our Regulatory Proposal and provides a summary of what we have heard and how this has influenced our Revised Regulatory Proposal
- **Chapter 3: Investment Priorities** - reiterates the investment priorities for Energex for 2025 and beyond, and discusses the AER's Draft Decision as it relates to our investment priorities and our proposed response
- **Chapter 4: Demand, Energy Delivered and Customer Forecasts** - updates the forecasts developed for the 2025-30 regulatory control period
- **Chapter 5: Capital Expenditure (capex)** - sets out our revised capex plans and provides additional information
- **Chapter 6: Operating Expenditure (opex)** - sets out our revised opex plans
- **Chapter 7: Incentive Schemes** - covers the application of incentive schemes

- **Chapter 8: Annual Revenue Requirement –** updates the proposed revenue required to enable us to continue to build and maintain a safe and reliable network
- **Chapter 9: Network Tariffs and Pricing –** discusses our proposed revised network tariff structure
- **Chapter 10: Metering –** sets out our response on legacy metering services
- **Chapter 11: Alternative Control Services (ACS)** - outlines our response relating to public lighting and other ACS, and
- **Chapter 12: Other Regulatory Matters** - briefly covers other related matters, including classification of services, control mechanisms, negotiating framework, pass through events, contingent projects and connection policy, and addresses confidentiality requirements.

We have adopted the "Accept, Modify and Justify" approach in our Revised Regulatory Proposal as follows:

- **Accept:** we are accepting the AER's Draft Decision on the basis that the AER has accepted the forecast or proposal as set out in our Regulatory Proposal or because the substituted forecast or proposal is acceptable
- **Modify:** based on the feedback from the AER, we are modifying our proposal to either change the project scope (e.g. where an alternative option is acceptable) or vary the forecast or proposal. This includes projects or programs where new information has become available since the submission of our Regulatory Proposal in January 2024, and
- **Justify:** we are maintaining that the initial forecast or proposal as set out in the Regulatory Proposal is prudent and efficient and are resubmitting our business cases with additional evidence to justify the need.

Our Revised Regulatory Proposal must be submitted to the AER within 45 business days of publication of the Draft Decision, which is by 26 November 2024. The AER will assess our Revised Regulatory Proposal and consult with interested stakeholders before publishing its Final Decision in April 2025. We encourage our communities and customers to make submissions to the AER as part of its consultation process on its Draft Decision and our Revised Regulatory Proposal. The key steps of the regulatory determination process are set out in Figure 1.

Figure 1: Next steps

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.

MESSAGE FROM OUR CHAIR AND CEO

This Revised Regulatory Proposal provides additional information to enable the AER to make its final determination on our 2025-30 investment plans, which we believe are in the long-term interests of South East Queensland's electricity consumers.

Our Revised Regulatory Proposal is focused on striking 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. Our unwavering commitment to delivering on this objective underpins Energex's response to the AER's assessment of our expenditure plans for the 2025-30 regulatory control period.

We respect the AER's role as a regulator in ensuring that Energex invests and operates efficiently to deliver a network that meets consumer needs now and into the future. We thank the AER Board and staff for their open feedback and ongoing constructive engagement on our proposals for the five-year regulatory control period. This Revised Regulatory Proposal provides additional information to enable the AER to make its final determination on our 2025-30 investment plans, which we believe are in the long-term interests of South East Queensland's electricity consumers.

Energex operates the electricity network in the growing region of South East Queensland. Our network is made up of many complex components designed to work together to deliver quality and reliable electricity to homes and businesses. This responsibility brings with it the challenge of maintaining sufficient capacity to supply every home and business on the days when electricity demand is at its maximum, no matter where they are connected on the network. Without the necessary prudent investment, Energex's ability to deliver a continuous and dependable supply of electricity to our customers would be notably impacted. Nevertheless, we are also mindful that we must meet our customers' energy needs in the most cost-effective and efficient way to maintain downward pressure on electricity prices in the long-term.

Queensland is in a period of strong economic, population and jobs growth, particularly in the South East region. As our communities in South East Queensland continue to grow, there will be more connections to the network and increased demand for power. This is coupled with Brisbane hosting the 2032 Olympic and Paralympic Games, which will drive expansion across areas of the network to ensure we concomitantly maintain our safety and reliability obligations.

Our Revised Regulatory Proposal further details the funding we propose is prudent for the next five-year period for the growing number of homes and businesses across South East Queensland who rely on us to provide a reliable electricity supply to meet their energy needs. This will include funding for investments that will reinforce areas of the network experiencing growth, support a higher penetration of renewables, and enable us to quickly restore supply to customers and communities following frequent severe weather events and natural disasters.

We will also continue to focus on facilitating customer opportunities in the energy transition. The energy system is undergoing complex, rapid and widespread change, with the proliferation of renewable energy sources targeting net zero emissions. The increased uptake of distributed energy sources, such as rooftop solar, provides significant opportunities for decarbonising the economy and empowering customers to both produce and consume energy. Our network therefore needs to have the capability and tariff structures in place to deliver for our customers.

To do our part in enabling the energy transformation, we know we must continue to increase our efficiency, execute faster and minimise our costs, so as to continue to deliver value for our customers and communities. Energex is focused on providing affordable electricity to support industry, economic development, employment, and affordable living. With this in mind, we will explore ways to further maximise network utilisation by targeting areas where capacity is available and collaborating with industrial businesses and local councils on their electrification projects. These may include the connection of new innovations, transport electrification projects, future data centres and industrial precincts in those targeted areas. This will lower costs for customers in the long-term and maximise use before spending on additional infrastructure.

Importantly, our Revised Regulatory Proposal has been informed by more recent targeted conversations with our customers that builds on the engagement program undertaken in the lead up to submitting our Regulatory Proposal earlier this year. These discussions were primarily focused on the investment required to manage growth in South East Queensland, network tariffs and customer service performance measures. We sincerely thank all those who have worked with us throughout our engagement process and provided valuable input into shaping our investment plans for the next five-year regulatory control period.

While customers have told us they value the services we provide and how we go about keeping the lights on, we also remain acutely aware of the cost of living pressures continuing to impact households and businesses across South East Queensland. Consequently, we have maintained our commitment to driving efficiency improvements and cost savings in how we deliver electricity to our customers. As a result, the estimated increase in distribution network charges for households will be limited to an average of $33 in each year of the 2025-30 regulatory control period.

Overall, we are confident that the investment plans detailed in this Revised Regulatory Proposal will provide long-term benefits for electricity consumers by focusing on: delivering electricity services in the most efficient and affordable way; providing a resilient electricity network to support a growing population and clean energy future; facilitating customer opportunities in the transition to renewable energies; and delivering the electricity infrastructure required for the Brisbane 2032 Olympic and Paralympic Games.

We appreciate and value the feedback provided to date on our investment and revenue recovery plans for 2025-30 and encourage further engagement through the next phase of the AER's consultation process. We will continue to work closely with the AER, customers and stakeholders to ensure a sustainable and affordable energy future for South East Queenslanders.

Sarah Zeljko
Chair
Energy Queensland Board

Peter Scott
Chief Executive Officer
Energy Queensland

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Executive Summary

Executive Summary

This Revised Regulatory Proposal sets out Energex's response to the AER's Draft Decision on our revenue proposal for the 2025-30 regulatory control period. Our Revised Regulatory Proposal details our acceptance of elements of the AER's Draft Decision and provides our justifications or modifications in other areas. It also includes additional input provided by customers and stakeholders through engagement activities undertaken since our Regulatory Proposal was published in January 2024.

Our Revised Regulatory Proposal is summarised below.[1]

Chapter 1: Context for our Revised Proposal

Energex is the DNSP for South East Queensland. We build, operate and maintain the distribution network from the New South Wales border north to Gympie and west to the base of the Great Dividing Range. We provide services to more than 1.6 million domestic and business customers, across a growing population base of around 3.8 million people.

While customers have told us their primary concern is energy affordability, our priorities and expenditure plans have also been influenced by a range of other challenges and opportunities (as discussed in Chapter 1). These include the significant ongoing electrification and continued high uptake of distributed energy resources, economic and population growth in South East Queensland and the increasing frequency and intensity of climate-related events that impact our network. Our plans have therefore 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.

Chapter 2: Customer and Stakeholder Engagement

Energex's Regulatory Proposal was informed by the views and preferences of our customers and stakeholders through business-as-usual and targeted customer engagement activities. Customers and stakeholders provided valuable insights on a range of themes, including the challenges they and their communities face and on specific issues on which we sought feedback.

The AER's Draft Decision found that Energex's engagement fell short of the *Better Resets Handbook – towards customer-centric network proposals (Better Resets Handbook)* expectations, particularly with respect to capital investment decisions and the issue of affordability.[2]

Since submitting our Regulatory Proposal and following publication of the AER's Draft Decision, we have undertaken "Phase 5 – Finalise" of our engagement program for the regulatory reset. This further engagement was focused on the capital investment required to manage growth in South East Queensland, network tariffs and application of the Customer Service Incentive Scheme (CSIS). Feedback provided by customers and stakeholders through this engagement has been integral to the development of this Revised Regulatory Proposal.

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 remains their primary concern, both from a cost of living and cost of doing business perspective.

Further information on the matters discussed with customers and stakeholders and a summary of feedback provided is set out in Chapter 2.

[1] All financial values in this Revised Regulatory Proposal are in real 2024-25 dollars, unless otherwise stated.
[2] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Overview*, September 2024, p. 6.

Chapter 3: Investment Priorities

In our Regulatory Proposal, Energex identified four investment priorities for the 2025-30 regulatory control period (refer to Figure 2). These investment priorities were informed by customer input. Chapter 3 discusses the AER's Draft Decision as it relates to our investment priorities and our response in this Revised Regulatory Proposal.

Figure 2: Our investment priorities

Chapter 4: Demand, Energy Delivered and Customer Forecasts

Electricity demand forecasts used to develop Energex's investment plans were set out in our Regulatory Proposal. Chapter 4 provides updated forecasts using the most recent actual data and inputs to ensure that this Revised Regulatory Proposal reflects reasonable expectations of forecast demand, energy delivered and customer numbers. There has been no change in approach to our forecasting methodologies.

Our updated system peak demand forecast has resulted in a higher peak demand than forecast in our Regulatory Proposal, driving the need for one additional network capital investment project. This project is to establish a new feeder to cater for strong growth in the Caboolture, Burpengary and Morayfield region.

Chapter 5: Capital Expenditure

In our Regulatory Proposal, for the 2025-30 regulatory control period, Energex forecast that $3,408.3 million (including asset disposals) of capital investment would be required to build and maintain our network assets, such as poles, wires, and transformers, connect new customers and invest in assets that support the network, including vehicles, depots, and information, communications and technology (ICT). On 28 June 2024, we submitted an updated capex model to the AER with an amended forecast of $3,341.1 million.

In its Draft Decision, the AER provided a substitute forecast of $2,801.0 million, which represents a reduction of 16.2 per cent compared to our updated capex forecast. The AER provided lower substitute forecasts for the categories of augmentation, resilience, non-network ICT, property, fleet and capitalised overheads.[3]

Energex's response to the AER's Draft Decision is to modify our capex forecast. Our revised capex forecast is $3,134.7 million (including asset disposals) for the 2025-30 regulatory control period, which is a 6.2 per cent reduction to our Regulatory Proposal. Energex has modified our augmentation, fleet and capitalised overhead capex forecasts and accepts the substitute forecasts for the remaining capex categories.

Our revised capex plans for the 2025-30 regulatory control period are set out in Chapter 5.

Chapter 6: Operating Expenditure

Energex proposed that $2,284.9 million in opex was required to fund the day-to-day costs required to operate and maintain our network assets. This includes inspecting, maintaining and repairing network assets, controlling vegetation growth, undertaking fault and emergency repairs and supply restoration, and providing customer service and corporate support activities.

The AER's Draft Decision accepted Energex's proposed opex forecast.[4]

However, because our proposed opex was based on a forecast 2023-24 base year, it has been updated in this Revised Regulatory Proposal to reflect actual data for 2023-24. Consequently, our forecast opex for the 2025-30 regulatory control period is now $2,510.2 million, a 9.9 per cent increase on our Regulatory Proposal forecast and the AER's Draft Decision.

We have made a 4.2 per cent efficiency adjustment to the base year, applied a 1.0 per cent productivity factor and included only one step change.

Chapter 6 sets out Energex's revised opex plans for the 2025-30 regulatory control period.

Chapter 7: Incentive Schemes

Through the application of incentive schemes, DNSPs like Energex are incentivised to run efficient businesses so that customers pay no more than is necessary for the services they require and ensure the right levels of service are delivered to customers.

For the 2025-30 regulatory control period, Energex proposed that the current incentive schemes, i.e. the Service Target Performance Incentive Scheme (STPIS), Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS), Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM), should continue to apply. However, given our customers' strong views that we should not be rewarded for good customer service we proposed that the customer service component (telephone answering) of STPIS should not apply. We also proposed that the CSIS and Export Service Incentive Scheme (ESIS) should not apply to Energex in the 2025-30 regulatory control period.

The AER's Draft Decision accepted Energex's proposal relating to the incentive schemes to apply for the 2025-30 regulatory control period but did not accept the proposal to exclude the telephone answering component of the STPIS.[5]

[3] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 8.

[4] AER, *Draft Decision, Energex Distribution Determination 2025 to 2030, Overview*, September 2024, pp. 15-16.

[5] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme*, September 2024, pp. 6-9.

Energex largely accepts the AER's Draft Decision, including the continued application of the telephone answering component of the STPIS. However, we have modified our position with respect to the application of the EBSS and propose that it should be suspended for the 2025-30 regulatory control period, for reasons set out in Chapter 7.

Chapter 8: Annual Revenue Requirement

In the Regulatory Proposal, Energex proposed that the total revenue required to continue to build and maintain a safe and reliable network for our customers is $8,151.5 million for the 2025-30 regulatory control period.

The AER's Draft Decision was to allow Energex to recover $7,973.2 million from customers, which is $178.3 million lower than proposed. This reduction was largely driven by a lower return on capital amount and reduced capex forecasts, which is partially offset by reduced negative revenue adjustments and a higher cost of corporate income tax.[6]

Chapter 8 sets out Energex's response to the AER's Draft Decision and proposes a revised forecast revenue of $8,140.8 million, which is $167.6 million more than the Draft Decision. The reasons for this proposed increase in revenue are related to updated opex, the proposed suspension of the application of the EBSS, revised forecast capex, and other mechanistic updates made to the calculation of the regulatory asset base (RAB).

Given our revised plans and revenues, in nominal terms, we estimate that the total annual network charges would increase by an average of:

- $33, or 4.6 per cent, annually for residential customers
- $100, or 4.6 per cent, annually for small business customers, and
- $1,804, or 5.3 per cent, annually for a large business connected on the low voltage network.[7]

Chapter 9: Network Tariffs and Pricing

Distribution network tariffs are the charges imposed by Energex to recover the costs of building, operating and maintaining the distribution network.

In January 2024, Energex submitted its proposed TSS and Tariff Structure Explanatory Statement (TSES) to the AER with our Regulatory Proposal. These documents provided information on our proposed network tariffs for the 2025-30 regulatory control period, developed in consultation with customers and stakeholders.

The AER's Draft Decision did not approve our proposed TSS. While the AER accepted many elements of the TSS, a number of changes were required. The fundamental change required Energex to shift default assignment for residential and small business customers with smart meters from time of use (TOU) demand tariffs to TOU energy tariffs, including reassigning customers currently on TOU demand tariffs to the TOU energy tariffs.[8]

Energex has accepted most elements of the AER's Draft Decision in our revised TSS. However, we have modified our proposal relating to the introduction of storage tariffs and, in response to

[6] AER, *Draft Decision, Energex Electricity Distribution Determination 2025-2030, Attachment 1 – Annual revenue requirement*, September 2024, pp. 6.

[7] 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 2.85 per cent based on the AER's methodology set out in the Post Tax Revenue Model (PTRM).

[8] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025-2030, Attachment 19 – Tariff structure statement,* September 2024, p. 4-6.

customer feedback, propose to defer the introduction of two-way tariffs to beyond the 2025-30 regulatory control period.

Further information is provided in Chapter 9.

Chapter 10: Metering

Residential and small business customers who do not yet have a smart meter installed continue to receive metering services from Energex. Our metering services include meter reading, meter maintenance and meter data services for our basic accumulation meters (or "legacy meters").[9]

In the Regulatory Proposal, we proposed that the service classification for legacy metering services should be changed from an ACS (i.e. user-pays) to a standard control service (SCS), with the costs to be recovered from all low voltage connected customers through network charges. We also proposed to accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of the 2025-30 regulatory control period.

The AER's Draft Decision accepted the majority of Energex's proposal. However, the AER made a reduction to the annual revenue requirement (due to updated model inputs) and introduced a true-up mechanism for opex to account for uncertainty of legacy metering replacement volumes.[10]

As discussed in Chapter 10, Energex accepts the AER's Draft Decision on metering in this Revised Regulatory Proposal and, as requested by the AER, has provided an amended bottom-up opex model to allow for the outworking of the true-up mechanism. Based on updated model inputs, our metering revenue forecast is now $376.0 million for the 2025-30 regulatory control period, which is 0.3 per cent lower than the Draft Decision.

Chapter 11: Alternative Control Services

ACS are distribution services that are customer-specific or customer-requested services and are paid for by the customer who seeks the service, including public lighting, security lighting, connection management services, and ancillary services.

Public lighting

The Regulatory Proposal outlined Energex's strategy to continue the deployment of light emitting diode (LED) public lighting to achieve 100 per cent LEDs by 30 June 2030. We also proposed 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 a user-pays approach for smart control devices (to be offered to customers from 1 July 2026). The proposed forecast revenue to be recovered from our public lighting tariffs in the 2025-30 regulatory control period was estimated to be $257.2 million ($, nominal).

The AER's Draft Decision accepted our public lighting strategy and made minor amendments to expenditure, revenue and pricing.[11]

Energex accepts the AER's Draft Decision with respect to public lighting.

[9] Prior to energy market reforms in 2017, Energex was responsible for the provision of metering services for all residential and small business customers. However, following those reforms, our role in the provision of metering services changed. We are now only responsible for managing and maintaining our existing fleet of "legacy meters" as they are gradually phased out and replaced by smart meters (which are the responsibility of energy retailers and metering service providers).

[10] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 20 – Metering services*, September 2024, pp. 6-7, 15.

[11] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, p. 15.

Other Alternative Control Services

Energex's proposed approach to other ACS, as set out in the Regulatory Proposal, was as follows:

- for fee-based ancillary services, we proposed changes to service dimensions and a rationalisation of our suite of services
- for quoted ancillary services, we proposed new labour rates and inclusion of a margin, and
- for security lighting, we proposed to cease providing and installing new security lights.

The AER's Draft Decision largely accepted our proposals with respect to fee-based ancillary services and security lighting. However, the AER did not accept the proposed labour rates for all quoted ancillary services categories.[12]

Energex accepts the AER's Draft Decision with respect to security lighting and fee-based ancillary services. We have also modified our proposal for quoted ancillary services and provided revised labour rates in this Revised Regulatory Proposal.

Further detail is provided in Chapter 11.

Chapter 12: Other Regulatory Matters

Our Regulatory Proposal addressed a number of other regulatory matters and requirements, including classification of services, control mechanisms, negotiating framework, pass through events, contingent projects and connection policy.

The AER's Draft Decision approved the control mechanisms, classification of services (except for the proposed reclassification of supply abolishment services to standard control), negotiating framework, nominated pass through events and connection policy to apply for the 2025-30 regulatory control period. Energex did not propose any contingent projects for the period.[13]

Energex accepts the majority of the Draft Decision but requests that the AER reconsiders the proposal to reclassify supply abolishment services from ACS to SCS for public safety reasons.

Chapter 12 provides more information.

Attachments

Our Revised Regulatory Proposal is complemented by supporting documentation, including a revised TSS. These documents are listed in each Chapter.

[12] Ibid, pp. 6, 11, 14.
[13] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, pp. 24-28.

A snapshot of our Revised Regulatory Proposal

Table 1: Standard control services

	2025-26	2026-27	2027-28	2028-29	2029-30
Forecast expenditures ($m, real $2024-25)					
Net capex	620.2	639.2	612.0	621.7	641.7
Opex (inc. debt raising costs)	505.8	503.2	501.4	500.4	499.4
Opening RAB ($m, nominal)	15,695.8	16,160.4	16,636.6	17,069.5	17,508.4
Revenue requirements ($m, real $2024-25)					
Annual revenue requirements (smoothed)	1,517.8	1,562.5	1,609.7	1,709.2	1,751.9
Weighted average cost of capital (WACC) (%)	5.88	5.90	5.94	6.02	6.10
X factor (%)	-6.32%	-2.95%	-3.02%	-6.18%	-2.50%
Nominal increase in revenue (%)	9.35%	5.88%	5.96%	9.21%	5.42%
Demand forecast 50 PoE (MW)	5,487	5,526	5,583	5,616	5,652
Customer numbers	1,658,594	1,678,004	1,697,474	1,716,888	1,736,169
Forecast energy delivered (GWh)	21,708	21,738	21,854	21,878	22,065

Table 2: Alternative control services

Matter	Position
Public lighting services	We will convert all existing conventional public lights to LED by 30 June 2030. We will 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 will cease to offer security lighting as a new installation from 1 July 2025 but will continue to maintain and operate legacy security lights. We have made changes to service dimensions for fee-based ancillary services and rationalised 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 revised labour rates specific to quoted services to ensure the recovery of actual costs.

Table 3: Key positions

Matter	Position
Service classification	The classifications as set out in the Final Framework and Approach (F&A) will apply but will also include the reclassification of legacy metering services as a SCS. We also propose that supply abolishment services should be reclassified from ACS to SCS.
Control mechanisms	The AER's control mechanism decision as set out in the Final F&A will apply, namely: • revenue cap for SCS, and • price caps for ACS.
Incentive schemes	The following incentive schemes as set out in the Final F&A will apply: • STPIS • CESS • DMIS, and • DMIAM. The following incentive schemes will not apply in the 2025-30 regulatory control period: • CSIS, and • ESIS. We propose that the EBSS will also not apply in the 2025-30 regulatory control period.
Nominated pass through events	The following nominated additional pass through events will apply: • 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 revised TSS outlines our proposed tariff structures for the 2025-30 regulatory control period. We are proposing to: • change default assignment for residential and small business customers with smart meters from TOU demand to TOU energy tariffs, including reassigning customers currently on TOU demand tariffs to TOU energy tariffs • strengthen the peak price signal • update TOU pricing windows • introduce new controlled load tariffs and grid-scale battery storage tariffs, and • streamline existing tariffs.

1.
Context for our Revised Proposal

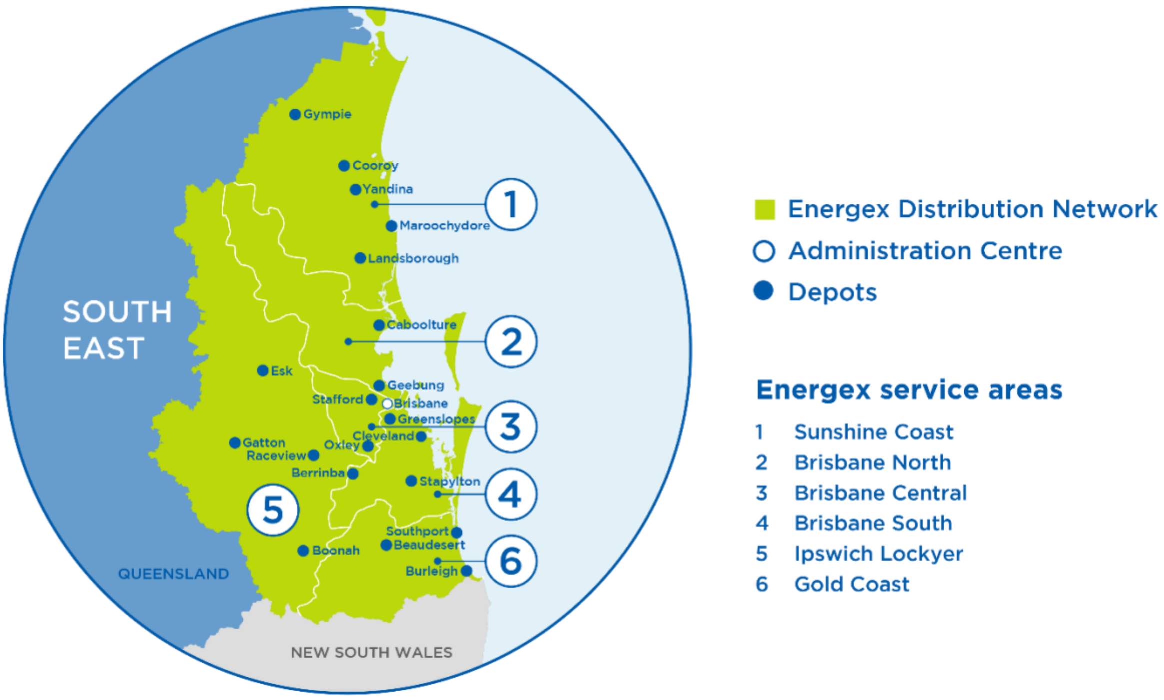
1.1 About Energex

Energex is a subsidiary of Energy Queensland, a Queensland Government-owned corporation. We manage an electricity distribution network which supplies electricity to close to 1.6 million residential homes and commercial and industrial businesses, serving a population of around 3.8 million. Taking supply from Queensland's transmission network service provider Powerlink, we operate and maintain one of Australia's largest electricity networks, covering an area of around 25,000 square kilometres in the growing region of South East Queensland, with a maximum demand of around 5,600 MW and delivering around 22,000 gigawatt hours (GWh) per year.

Our distribution network runs from the New South Wales border in the south to Gympie in the north and west to the base of the Great Dividing Range. It includes the major population areas of Brisbane, the Gold and Sunshine Coasts, Ipswich, Redlands, Logan, and Moreton Bay. Figure 3 below shows our distribution area.

Power is supplied to our customers through more than 35,000 kilometres of overhead powerlines, 21,000 kilometres of underground cables, 246 zone substations, 42 bulk supply substations and over 52,000 distribution transformers.

Figure 3: Our service area



1.2 Our operating environment

Led by consumers' desire for lower cost and low emissions energy, our traditional poles and wires business is rapidly transforming towards a decentralised, two-way power system. The increasing number of households and businesses investing in rooftop solar generation and energy storage capabilities is driving a more complex energy system. Forecasts indicate that this trend will accelerate into the future, presenting new challenges, including rapidly declining minimum demand and significant reverse power flows (in contrast to traditional one way flows) across some parts of the distribution network, as well as system security, stability and operational risks.

The energy system has been undergoing complex, rapid and widespread change with the proliferation of renewable energy sources targeting net zero emissions. The increased availability of distributed energy resources, such as rooftop solar, provides significant opportunities for decarbonising the economy and empowering customers to both produce and consume energy.

The contextual environment of the dynamic energy industry in Queensland, and more broadly across Australia, has influenced our priorities and the development of our expenditure, revenue and tariff plans. The challenges and opportunities for Energex have never been greater or more complex and include:

- **Energy affordability** - rising cost of living and cost of doing business pressures, driven by elevated inflation and interest rates, remain a core concern for our customers
- **Maximising asset utilisation** – maximising network asset utilisation before spending on additional infrastructure to meet the challenges of the energy transition and the growth in demand provides opportunities to lower costs for consumers in the long-term
- **Significant ongoing electrification** – the electrification of homes and businesses, characterised by the continued uptake of electric vehicles and other electrically powered appliances and technologies, is expected to contribute to an average growth in system peak demand of 0.8 per cent per year during 2025-30
- **Queensland's growing economy** – industry, population and jobs growth in South East Queensland is expected to result in an increase in new connections to our network of 2.3 per cent per year, while the Brisbane 2032 Olympic and Paralympic Games (Brisbane 2032) is also likely to stimulate significant infrastructure and economic growth
- **Growth in the uptake of distributed energy resources** – the potential for rooftop solar to grow by 10.5 per cent annually will provide challenges in managing minimum demand on the network, while managing charging of batteries, including electric vehicles, can offer opportunities for customers and improve network utilisation
- **Decreasing daytime minimum demand** – the trend towards high penetration of renewable, decentralised generation has the potential to cause locational network reliability and security issues
- **Climate change and the environment** – the increasing frequency and intensity of weather and climate-related events impacts on the life of our assets and infrastructure, and reinforces the importance of having a resilient network and strong disaster response capability
- **Security of critical infrastructure** – greater interconnection and increased digitalisation of electricity (e.g. smart meters and smart energy management devices) will provide more information about our network and enable more use of demand response, but also increase the risk of threats to our critical infrastructure and cyber environment, and

- **Ongoing regulatory and policy change –** as the energy transition continues to gather pace, changes to the rules that regulate the National Electricity Market will impact the way we operate and manage our network.

Our customers and communities are directly impacted by our operations which are crucial to powering their lifestyles and businesses. We must therefore continue to focus on striking 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.
Customer and Stakeholder Engagement

Key messages:

- Engaging with and listening to our customers and stakeholders is a fundamental component of our business-as-usual activities and has been integral to the development of this Revised Regulatory Proposal.
- Our Revised Regulatory Proposal has been informed by additional engagement with customers and stakeholders.
- Customers and stakeholders 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 and stakeholders 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 a primary concern, both from a cost of living and cost of doing 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 into the future and efficiently delivering electricity services in an affordable way that provides value to our customers and communities across South East Queensland.

2.1 Overview

Engagement with our customers and stakeholders is a fundamental aspect of our daily operations at Energex. For the regulatory determination process, we built upon this foundation by establishing our Customer and Stakeholder Engagement Strategy and Customer and Stakeholder Engagement Plan[14] through proactive engagement and co-design with customers, our Customer and Community Council (CCC), and various other stakeholders representing a cross-section of customer cohorts.

This chapter focuses on and discusses how, since the submission of our Regulatory Proposal to the AER in January 2024, we have continued to actively involve our customers and stakeholders in more detailed conversations that have further informed our decision-making and the development of this Revised Regulatory Proposal and TSS. This chapter covers "Phase 5 – Finalise" of our regulatory reset engagement undertaken between April and October 2024 (refer to Table 4) and focuses on the topics and issues raised in both the AER's Issues Paper published in March 2024[15] and Draft Decision published in September 2024.

More detailed information relating to our engagement activities and the insights provided by our customers and stakeholders used to inform our Regulatory Proposal is available on our Talking Energy website.

[14] These documents are available on the Talking Energy website.
[15] AER, *Issues Paper: Ergon Energy and Energex electricity distribution determinations 2025-30*, March 2024.

Table 4: 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 South East 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 - Oct 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 2025-30 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.

2.2 Our response to the AER's Draft Decision

The AER's Draft Decision sets out its views on Energex's customer engagement process for our regulatory determination. The AER concluded that, overall, our engagement fell short of what is expected under the *Better Resets Handbook*.[16] A key concern was that discussions on capex were mainly confined to our Reset Reference Group (RRG) and that we did not engage with customers on this key area of our proposal (i.e. our engagement was limited to informing stakeholders about our capex investment plans). Further, the AER found that while the issue of affordability raised by customers was a key theme of our proposal, the absence of meaningful, comprehensive consultation on future investment decisions with end-use customers meant that the issue of affordability was unable to be fully considered.[17]

We acknowledge that our engagement started late and consequently had a narrow scope as a result. The focus for our Regulatory Proposal was on engaging with customers in the time available to us on those areas where they could meaningfully impact our proposals. Key areas where customers influenced our Regulatory Proposal were the choice to not have a CSIS, to remove the customer service (telephone answering) component of the STPIS, and to build up pace in our network tariff reform journey. We note that the AER did not accept our customers' recommendation to remove the customer service (telephone answering) component of the STPIS[18] and, while it did accept customer decisions around some of our network tariff parameters, it did not accept our proposed default tariffs for residential and small business customers.[19] This was disappointing considering our customers' and Network Pricing Working Group's (NPWG's) support for these tariffs.

To address concerns about our lack of engagement on capex, we further engaged with our Voice of the Customer (VOC) Panel, asking them for their views on a major component of our network capex (i.e. our augmentation expenditure). We understand that, at this stage of the process, this engagement cannot be as fulsome as we would like but we are confident that this engagement will lay the foundation for a stronger focus on genuinely engaging with our customers on the underlying drivers of our expenditure and the long-term price outcomes for consumers going forward.

To achieve our long-term engagement goals, we have revised our Customer Strategy which will be a key enabler to realising the Energy Queensland 2032 Corporate Plan, in particular the strategic objectives centred around "Experience Excellence". The Customer Strategy incorporates feedback from our Customer Engagement Review and our CCC and RRG, which will result in Energex doing a number of things differently to enhance our customer engagement capability. The strategy has a principles-based approach, including the principles of *Know our customers, Empower our customers, Make it easy* and *Collaborate to deliver value*. Initiatives and a road map that underpins the Customer Strategy are under development.

Energex has committed to establishing a new framework through which issues pertaining to the regulatory reset process, including our investment and revenue recovery plans and related performance, will be discussed on an ongoing basis with customers and stakeholders. The Customer and Stakeholder Engagement Framework, which supports our refreshed Customer Strategy, was developed in response to our learnings from the 2025-30 Regulatory Proposal customer and stakeholder engagement process. This Framework, recently consulted on with our CCC, provides for the establishment of sub-committees of our CCC to facilitate breadth and depth

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[16] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Overview,* September 2024, p. 6.
[17] Ibid, p. 6.
[18] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme,* September 2024, p. 6.
[19] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 19 - Tariff structure statement,* September 2024, p. 5.

of discussion, and disclosure and exploration of our strategic and operational plans. The sub-committees will be sponsored by the relevant Executive or General Manager in the areas of, “Grid of the Future”, “Customer Service and Digital”, “Tariffs and Affordability” and “Asset Management, Resilience and Safety” (subject to further consultation) and will see regular and continuous disclosure of critical information, including asset management plans and projects. In addition, the new CCC will include an independent Chair drawn from the Council membership. This structural change was prompted by lessons learned through the 2025-30 Regulatory Proposal program of work and review of the Customer Strategy, including analysis of approaches by other DNSPs.

Importantly, the new Framework will establish a standing VOC Panel whose membership will be drawn from across our customer base to enable direct input from end-use customers, in addition to that obtained from other customers and stakeholders through the main CCC. The new enduring VOC panel of Queenslanders will be constituted and will see a group of Queenslanders that have been through a capacity building program remain as a regular sounding board for initiatives and take part in our regular disclosure program. This underscores an enhanced commitment to engagement in alignment with the IAP2 Spectrum of Public Participation to ensure consumers are consulted with on a range of issues, with a goal of consumers having more influence at the upper “empower” end of the IAP2 spectrum. We will, in line with the *Better Resets Handbook*, encourage consumers to test assumptions and processes that underpin our operations.

Recruitment of new CCC members and additional VOC members will commence in 2025.

2.3 Engagement activity for “Phase 5 – Finalise”

Our “Phase 5 – Finalise” engagement focused on revisiting some of the topics and issues on which we engaged in Phases 1 – 4 and exploring some new topics and issues following feedback from customers and stakeholders on our Regulatory Proposal, including from the AER, Consumer Challenge Panel (CCP) and RRG. This feedback was either provided directly to us or through written submissions in response to the AER’s Issues Paper.

The release of the AER’s Draft Decision provided another opportunity to consult with customers and stakeholders to further test, refine, and eventually finalise our investment and revenue recovery plans for the 2025-30 regulatory control period as set out in this Revised Regulatory Proposal. The sections below provide a summary of the engagement activities undertaken through “Phase 5 – Finalise”, the issues discussed, and insights obtained.

2.3.1 Customer and Community Council

The CCC includes a range of organisations that represent the interests of our customers and communities across Queensland. It has played a key role in advising on our approach to engagement by providing a sounding board for our investment and revenue recovery plans during the different phases of engagement. Many CCC members also hold positions on or attend some of our other engagement mechanisms, including the RRG, NPWG, Agriculture Forum, Public Lighting Forum and Energy Academy (electrical contractor forum). The CCC’s involvement in these discussions provided an important linkage between the topics and issues explored in conversations across the different groups and interpretation of the insights provided.

During “Phase 5 – Finalise” the CCC met three times - in April, June and November 2024. At each of its meetings, the CCC was updated on the insights provided by customers and stakeholders through our other engagement activities and how we were considering them in our evolving thinking and decision-making on our investment and revenue recovery plans outlined in this Revised Regulatory Proposal.

A key contribution of the CCC during the "Phase 5 – Finalise" engagement was to work with Energex to develop a suite of customer service performance measures. This suite of measures was developed based on the insights and preferences provided by our VOC Panel participants on the CSIS and customer service. The CCC assisted Energex in identifying suitable performance measures and metrics to socialise with the VOC Panel as part of our commitment to improving transparency in our customer service performance. Further information on the outcome of the CSIS and related customer service performance measures discussion with the VOC Panel is provided in section 2.3.3.

2.3.2 Reset Reference Group

Throughout "Phase 5 – Finalise" of our engagement plan, we continued to engage with the RRG. The RRG's primary purpose during the engagement process has been to engage in constructive collaboration with Energex to develop and execute our Customer and Stakeholder Engagement Plan, and to challenge us on our approach to investment and revenue recovery matters in the interests of ensuring positive outcomes for customers.

Following our Phases 1 - 4 engagement activities, the RRG told us that although they believed the engagement we undertook to develop the Regulatory Proposal fell short of expectations, they did recognise that Energex was committed to engaging with customers and stakeholders and acknowledged the positive role our Board and Executive played in our engagement activities. The RRG further advised that they believed there was room for improvement going into "Phase 5 – Finalise" and encouraged us to provide more time and resources for our engagement activities. In particular, the RRG recommended that more pricing information should be provided to customers and stakeholders to assist them in making value judgements in relation to the engagement topics. Furthermore, the RRG told us they believed that our "Phase 5 – Finalise" engagement provided an opportunity to expand our conversation with customers to cover important topics, such as capex, that had not been engaged on prior to the submission of our Regulatory Proposal. This feedback was actioned through engaging with the VOC Panel (discussed in section 2.3.3).

Building on its observation of our engagement activities, we continued to meet with the RRG regularly to develop our engagement activities for "Phase 5 – Finalise". In particular, our key engagement mechanisms centred on the VOC Panel and NPWG, as discussed below.

Input on the technical aspects of our proposal provided by the RRG throughout "Phase 5 – Finalise", including feedback provided in the "technical report" submitted as part of the AER's Issues Paper consultation,[20] have been considered by Energex alongside all other customer and stakeholder feedback and used to inform the decisions outlined in this Revised Regulatory Proposal.

2.3.3 Voice of the Customer Panel

As part of our continued customer engagement, we reconvened the VOC Panel in both August and October 2024, with the sessions independently facilitated by engagement specialists MosaicLab. The VOC Panel, originally established in 2023, has been an instrumental component of our customer engagement, providing an important mechanism through which we were able to obtain insights from across our diverse residential customer base in South East Queensland. These insights were integral to the development of our Regulatory Proposal and this Revised Regulatory Proposal.

[20] Reset Reference Group, *Engagement Report for the 2025-2030 Energex Regulatory Proposal*, March 2024, available on the AER's website.

To improve efficiency during “Phase 5 – Finalise” we combined our Customer Focus Group participants from previous engagement phases with the VOC Panel to ensure we maximised the number of end-use customers participating in the engagement process and our ongoing conversations. A total of 27 end-use residential customers participated in the online August and October 2024 VOC Panel sessions across two full days. These customers provided their insights into how Energex should plan for the future, while providing affordable services that meet changing customer and community needs.

The VOC Panel session in August 2024 provided an opportunity to update participants on how their insights and recommendations (from both the VOC Panel and Customer Focus Group) influenced our investment and revenue proposals. Importantly, and as recommended by the RRG, we shared customer impacts around pricing in terms of the year-on-year likely price increases for customers over the 2025-30 regulatory control period based on our investment plans. The session also enabled us to discuss measures Energex proposes to adopt to limit those price increases, with customer concern around affordability and cost of living pressures in mind.

The August 2024 VOC Panel also provided the opportunity for Energex to update participants on our position on the CSIS and discuss customer preferences around openness and transparency in customer service performance measures. Participants provided input into the key services and related measures they considered were important to form part of a new Customer Service Performance Measures Scorecard to be introduced by Energex at the commencement of the 2025-30 regulatory control period.

A key focus for the August and October 2024 VOC Panel sessions was engaging with customers on the capex required to manage growth in South East Queensland. In August, we explored our proposed augmentation plans to cater for population growth and increasing network demand in the South East, as well as the associated costs and price impacts for customers. Following publication of the AER’s Draft Decision, the October 2024 VOC Panel session focused on the outcomes of the Draft Decision, especially as it pertained to augmentation of our network. In addition, the October VOC Panel session covered pricing impacts within the context of affordability, network tariffs, the CSIS and customer service performance measures. This provided Energex the ability to test and refine our thinking on key issues in relation to our proposed capex within the context of the AER’s Draft Decision with our VOC Panel participants.

In summary, VOC Panel participants told us the following:

- **Affordability:** participants generally understood and were accepting of our proposed investment plans over the 2025-30 regulatory control period and the associated year-on-year customer pricing impacts. However, noting that affordability and cost of living pressures were still of concern to customers, they have an expectation that Energex will continue to focus on efficiency and prudent investment to reduce costs where possible
- **Network tariffs:** participants appreciated there were mixed views on the pace of change around tariff reform, particularly with respect to the introduction of two-way pricing. Notwithstanding which tariffs are approved, participants considered that customer choice in network tariffs was important. Further, they were of the view that education and awareness is of vital importance to enabling customers to make informed network tariff choices and energy solution investments where practical and possible
- **Managing growth:** participants expect Energex to consider prudent investment in growth-related network augmentation, balancing the costs of investment in the 2025-30 regulatory control period against future costs if augmentation projects related to accommodating growth in South East Queensland were delayed into the future. They made it clear that they expect current network reliability performance to be maintained, and

- **CSIS and Customer Service Performance Measures:** participants remain opposed to the concept of the CSIS, but generally accepted the AER's Draft Decision in regard to maintaining the telephone answering component of the STPIS. This view was based on Energex's commitment to publishing a new Customer Service Performance Measures Scorecard independently of the regulatory determination process. This scorecard will provide a performance report on the services that VOC Panel participants told us were important to them, namely: Customer Contact: Call Centre (interactions); Customer Contact: Self-serve Channels (portal and website); Power Outages (planned and unplanned); Connections (offer made and supply available); and Complaints (handling and resolution).

An overview of the insights provided by VOC Panel participants on these issues is available on our Talking Energy website.

More information on how these insights have informed the different elements of this Revised Regulatory Proposal is provided in subsequent chapters.

2.3.4 Network Pricing Working Group

During our "Phase 5 – Finalise" engagement, and in response to customer and stakeholder feedback, we took the opportunity in February 2024 to refresh and renew our NPWG membership. The aim was to broaden the customer and stakeholder base represented in the NPWG ahead of further network tariff reform-related discussions to inform this Revised Regulatory Proposal and associated TSS. Through an expression of interest process, we extended the NPWG membership beyond that of the RRG and CCC members to include other interested parties representing not only our residential and business customers, but also energy retailers and energy industry professionals.

The refreshed NPWG, which was independently facilitated by MosaicLab, met five times between April and October 2024 and was tasked with:

- reviewing the TSS that had been developed with insights provided by the previous NPWG members and other customer and stakeholder engagement on network tariffs conducted throughout 2023, including with the CCC, Agriculture Forum, VOC Panel, Large Customer Forum, and Public Lighting Forum
- considering the network tariff-related customer and stakeholder submissions received and outputs from the AER's Issues Paper consultation
- considering the AER's Draft Decision on the TSS, and
- reaching consensus, where possible, on key elements pertaining to the issues identified as part of the outcomes of the AER's Issues Paper consultation, and ultimately, the network tariff reform and tariff structure-related elements of the AER's Draft Decision.

Subsequently, the NPWG conversations through "Phase 5 – Finalise" explored the following network tariff-related topics and issues in depth:

- load control tariffs and the Queensland Electricity Connection Manual (QECM)
- dynamic connections and two-way tariffs
- storage tariffs and the level of fixed charges
- TOU energy tariffs for customers consuming 100-160MWh per annum, and
- demand tariffs and their appropriateness as the default tariffs for residential customers.

A summary of agreed positions on each of the issues outlined above from the NPWG session held in October 2024 is provided in the TSES.

2.3.5 Large customers (including commercial and industrial)

We continued to engage with large customers (including commercial and industrial) across the different large customer classifications, including our Standard Asset Customer (SAC) – Large, Connection Asset Customer (CAC) and Individually Calculated Customer (ICC) base.

Learning from our engagement with large customers during Phases 1 – 4, our "Phase 5 – Finalise" engagement with large customers focused on the key issue they identified was of primary interest to them, i.e. network tariffs.

Additionally, our engagement approach during "Phase 5 – Finalise" took the form of more individualised contact where all large customers were communicated with and provided an opportunity to engage with Energex through individual one-on-one discussions. These discussions were intended to enable large customers to explore their business operations now and into the future, raise any specific issues of concern with our Regulatory Proposal and, importantly, discuss individual customer impact based on the network tariffs proposed for different customer classifications. This individualised, one-on-one approach to engagement enabled a depth of conversation with those large customers who took up the offer of engaging with us that could not be explored in an open forum due to commercial-in-confidence considerations.

Although the specific details of those discussions remain commercial-in-confidence, at a summarised high-level, our large customers continue to tell us that affordability and the cost of electricity is a key component and consideration in their overall competitiveness and costs of doing business. Energy costs, along with other considerations, continue to influence their decisions around future investments in both their general business operations and in potential new energy solutions to manage their energy use. Importantly, our large customers highlighted that early notification of price impacts and future forecasting relating to pricing impacts of network tariffs is key to assisting them in both their short to medium-term budget-setting process and medium to long-term investment decision-making.

See the TSES for more information on how the insights from large customers have informed our plans for network tariff reform and the 2025-30 TSS.

2.3.6 Public Lighting Forum

Through "Phase 5 – Finalise" we held three separate Public Lighting Forums - in February, March and October 2024 - to further engage our public lighting customers and stakeholders on both regulatory determination and other business-as-usual engagement topics. The sessions provided Energex with the opportunity to update participants on the public lighting-related proposals submitted to the AER in our Regulatory Proposal in January 2024, the AER's Issues Paper consultation (including the public lighting issues raised and the process for customers and stakeholders making submissions to the AER) and the AER's Draft Decision regarding public lighting matters.

2.3.7 Other engagement activity

As part of our business-as-usual engagement activities we have also continued to engage with other customers and stakeholders through a wide range of activities in addition to those outlined above. We have continued to engage and receive insights from local councils, community representatives, Agriculture Forum members, Demand Flexibility and Innovation Working Group members, electrical contractors and other industry professionals, energy retailers and developers.

Additionally, our customer research and insights program, which includes surveying customers in relation to customer experience, customer satisfaction and trust, continues to provide us with rich insights on our service performance and what customers need and expect in terms of service delivery and in interacting with our business.

Our Queensland Household Energy Survey 2024,[21] conducted in March and April 2024, has provided valuable insights into our residential customers' perceptions around energy in general and, more specifically, their perspectives on energy affordability, their energy behaviours and, importantly, their energy-related purchasing intentions (e.g. solar PV, electric vehicles, and battery storage) both presently and in the next three to 10 years.

The insights from these other engagements, combined with our bespoke regulatory engagement activities outlined above, have been blended to provide a holistic view of what our customers and stakeholders have told us is important to them.

2.3.8 Engagement activity summary

Table 5 provides an overview of the engagement activities undertaken with our customers and stakeholders over the different phases of engagement identified in our Customer and Stakeholder Engagement Plan.[22] Collectively, the conversations had with our customers and stakeholders through those engagement activities and the rich insights they provided have evolved our thinking and proposals outlined in this Revised Regulatory Proposal.

Table 5: Overview of customer and stakeholder activity (Phases 1 – 5)

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	Phase 5 Finalise Apr-Oct 2024
CONSUMER 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: Energex speaker at roadshows)*	-	✓	-	-	-

[21] Available on the Queensland Household Energy Survey website.
[22] Available on the Talking Energy website.

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	Phase 5 Finalise Apr-Oct 2024
	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	-	✓	-	-	✓
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 and 2024 *(Note: 2,358 Energex customers responded in 2024)*	-	✓	-	-	✓
Residential Customers	Customer Focus Group Workshops x 2 with Customer Focus Group members joining the Energex Voice of the Customer Panel in Phase 5	-	-	✓	✓	✓
	Residential Customer Tariff Interviews	✓	-	-	-	-
	Residential Network Capacity Tariff Trial *(Partner: Ergon Energy Retail)*	✓	✓	✓	✓	-
Residential Customers who have had a recent interaction with Energex	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	-	✓	-	-	-

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	Phase 5 Finalise Apr-Oct 2024
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	-	✓	-	-	-
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	-	-	✓	✓	-
	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	-	✓	✓	✓	-
	Individual business-to-business meetings	-	✓	✓	✓	✓
ENERGY PARTNERS						
Energy Retailers	Energy Retailer Meetings *(main 6 retailers in Queensland bi-monthly)*	✓	✓	✓	✓	✓

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	Phase 5 Finalise Apr-Oct 2024
	Energy Retailer Forum *(all energy retailers)*	-	-	✓	✓	-
	Annual Energy Retailer Satisfaction Survey	-	✓	-	-	✓
Electrical Contractors	Electrical Contractor Peak Body Meetings *(meetings individually with Master Electricians Australia and National Electrical and Communications Association)*	✓	✓	✓	✓	✓
	Energy Academy Forum *(Electrical contractors forums)*	✓	✓	✓	✓	✓
EMPLOYEES						
Energy Queensland Employees	Energy Queensland employees (all brands)	✓	✓	✓	✓	✓
	Industry Partners	✓	✓	✓	✓	✓

2.4 Engagement insights and our response

At a high-level, across each of the phases of engagement, we have consistently heard the following key insights from our customers and stakeholders:

- safety should never be compromised
- electricity affordability is a concern for many customers, both from a cost of living and 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 distributed energy resources, 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.

Table 6 builds on the previous energy challenges or opportunities on which we engaged with our customers and stakeholders as part of our Regulatory Proposal engagement. Specifically, it focuses on those energy challenges and opportunities engaged on during "Phase 5 – Finalise", some revisited and others new, and outlines what customers and stakeholders told us and how we are responding through this Revised Regulatory Proposal.

Further details on the insights provided by customers and stakeholders and how they have influenced our thinking and been considered in our decision-making are addressed throughout the relevant chapters in this Revised Regulatory Proposal.

Table 6: Engagement insights and our response overview

Energy challenge or opportunity	What customers and stakeholders 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 doing 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 1.0 per cent productivity factor to opex and capitalised overheads, and self-fund the capital spend above forecast for ICT for the last five years (2018-19 to 2022-23). We will continue to refine our network tariffs to enable our customers to benefit from the renewable energy transition and reduce their network bill by changing their energy consumption patterns.
Network tariff reform	Network tariff reform should proceed with equity, fairness and cost-reflectivity in mind in the design of tariff structures. Information, education and awareness for customers is key to enabling them to make informed tariff choices and behind the meter energy solution investments based on their individual circumstances.	We will continue to reform our network tariffs to provide opportunities for 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. 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 and stakeholders told us	How we are responding
Capex – Augmentation	Customers support prudent augmentation expenditure to cater for expected growth across South East Queensland both now and into the future. Customers want a reliable and safe network that provides for all customers across South East Queensland and do not want reliability and safety standards to be compromised.	We proposed investment to cater for the significant growth within the South East Queensland region, but a large portion of this investment was not accepted by the AER due to differing interpretations of a jurisdictional Distribution Authority requirement. We remain committed to providing a reliable network for our growing communities across South East Queensland. We have enhanced our business cases to better articulate the underlying drivers and customer benefits for these investments and have resubmitted this proposed investment for the AER's consideration.
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. However, they are generally accepting of maintaining the status quo in relation to the STPIS (telephone answering component) given it already exists. Customers want ease of interaction with us through their preferred communication channels and would like to see greater channel choice and flexibility, particularly around website and portal use. Customers want 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 connections. 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 supported the feedback from customers and proposed that the CSIS should not apply for 2025-30, which was accepted by the AER in its Draft Decision. Given the AER's Draft Decision to retain the customer service (telephone answering) component of STPIS and following socialisation of this decision with our customers, we propose to keep the telephone answering component of STPIS for the 2025-30 regulatory control period. We will maintain our contact centre and online channels to provide choice around how customers engage with us. Independent of the regulatory determination process and requirements, we have committed to publishing a Customer Service Performance Measures Scorecard from the commencement of the 2025-30 regulatory control period focused on services that our customers have told us are important to them: Customer Contact: Call Centre (interactions); Customer Contact: Self-serve Channels (portal and website); Power Outages (planned and unplanned); Connections (offer made and supply available); and Complaints (handling and resolution).

Energy challenge or opportunity	What customers and stakeholders told us	How we are responding
Energy efficiency in public lighting	Customers support the full deployment of LED lights by 2030 due to the financial and environmental benefits. Customers generally support a user-pays approach for the deployment of smart control devices as prudent and providing access to this technology to customers while there is still uncertainty on their use as metering devices. Customers want us to consider extending the cost recovery timeframe out to 2035 for the residual value of remaining conventional public lighting.	Our co-designed public lighting strategy provides for a transition to 100 per cent LED public lighting by 2030. The AER accepted our public lighting strategy, which we will implement for the 2025-30 regulatory control period.

2.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
MosaicLab - Customer Panel and Focus Groups Report August 2024	2.01	Energex - 2.01 - MosaicLab Customer Panel and Focus Groups Report - August 2024 - public
MosaicLab - Customer Panel and Focus Groups Report October 2024	2.02	Energex - 2.02 - MosaicLab Customer Panel and Focus Groups Report - October 2024 - public

3.

Investment Priorities for 2025-30

Key messages:

- Our customers remain concerned about the affordability of electricity.
- There were no material issues raised on our investment priorities by the AER, customers or stakeholders.
- This Chapter discusses the AER's Draft Decision as it relates to our investment priorities and our response in this Revised Regulatory Proposal.

3.1 Overview

Our Regulatory Proposal identified four investment priorities for the next regulatory control period. These priorities were informed by customer feedback from our business-as-usual and targeted engagement activities, as well as consideration of our external environment and the key challenges and opportunities Energex and our customers will be facing in 2025 and beyond.

There were no material issues raised with our investment priorities by respondents to the AER's Issues Paper or during our "Phase 5 – Finalise" engagement. The AER also did not provide any specific commentary on our investment priorities in its Draft Decision.

The key priorities that will drive Energex's investment plans for 2025-30 are as set out in Figure 4.

Figure 4: Our investment priorities

3.2 Our response to the AER's Draft Decision

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

In our Regulatory Proposal, we committed to spending only what is necessary to meet the energy needs of South East Queensland, and in so doing minimise price increases for our customers. To that end, we undertook to strike the right balance between investing into the network to provide clean, reliable and smart electricity and addressing our customers' affordability concerns.

To do our part in enabling the energy transformation, we know we must continue to increase our efficiency, execute faster and minimise our costs, so as to continue to deliver value for our customers and communities. Energex is focused on providing affordable electricity to support industry, economic development, employment, and affordable living. With this in mind, we will explore ways to further maximise network utilisation by targeting areas where capacity is available and collaborating with industrial businesses and local councils on their electrification projects. These may include the connection of new innovations, transport electrification projects, future data centres and industrial precincts in those targeted areas. This will lower costs for customers in the long-term and maximise use before spending on additional infrastructure.

In addition to maximising utilisation of our network and only spending what is required to meet customer needs, we proposed to self-fund additional ICT capex above the AER allowance for the period of 2018-19 to 2022-23 and apply an annual 1.0 per cent productivity factor to both opex and capitalised overheads to account for expected efficiency improvements and cost savings in how we deliver electricity to our customers.

The AER's Draft Decision adopted Energex's affordability measures but expressed concern about the level of engagement with customers and stakeholders on investment decisions and the associated issue of affordability.[23]

Since publication of the AER's Draft Decision, we have undertaken further engagement with customers and stakeholders, with a key focus on the investment required to manage growth in South East Queensland. Our recent engagement has again highlighted that electricity affordability remains customers' primary concern from both a cost of living and cost of doing business perspective. This is consistent with the results of the 2024 Queensland Household Energy Survey, where 55 per cent of South East Queensland residents indicated that they were highly concerned about their ongoing ability to pay their electricity bills.[24] Consequently, delivering electricity services in the most efficient and affordable way remains our foremost priority.

However, while our customers continue to make it clear that affordability of electricity is their paramount concern, they also expect us to provide a smart electricity grid and the necessary infrastructure to support increased demand, enable customer choice for distributed energy resources, such as rooftop solar systems, battery storage systems and electric vehicles, and continue to provide a safe and reliable electricity supply. These priorities are reflected in our proposed five-year investment plans.

In this Revised Regulatory Proposal, we remain mindful of the need to provide electricity services in the most cost-effective and efficient way to maintain downward pressure on electricity prices in the longer-term. In addition to applying our affordability measures, our overarching aim continues to be to spend no more than is necessary to deliver on our customers' expectations.

[23] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Overview*, September 2024, p. 6.

[24] The 2024 Queensland Household Energy Survey, which is available on our Talking Energy website, was completed by 2,358 Energex customers, with 55 per cent rating their concern around their ongoing ability to pay their electricity bills as a 7-10 on a 0-10 scale where 0 equals not concerned at all and 10 equals very concerned.

3.2.2 Investment priority 2: Provide a resilient electricity network to support a growing population and clean energy future

In our Regulatory Proposal, Energex highlighted that in light of the transition to a clean energy future and the expected growth in South East 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 need to 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 need to transform the network into a more intelligent and dynamic grid to manage and enable more distributed energy resources to be connected at lower cost.

The AER's Draft Decision accepted our proposed connection and distributed energy resources-related capex, allowing us the investment required to connect new customers to the network and ensure the efficient integration of renewables and clean energy. This investment also provides some support for improving grid visibility. Further, the AER accepted our proposed cyber security investments, so that we can manage our cyber security risks.[25]

The AER did not accept a large portion of our proposed investment intended to cater for the significant growth within the South East Queensland region. The main driver for the AER's Draft Decision on our growth investment is that it disagreed with our interpretation of a jurisdictional Distribution Authority requirement known as the Safety Net.[26]

Given that the Queensland regulator, being the Department of Energy and Climate, supports our interpretation and that we have been operating under our and the regulator's interpretation since 2014, we submit that our interpretation of the Safety Net provisions, and the resultant projects that form part of our augmentation capex submission, are required to meet our Distribution Authority obligations. We have enhanced our business cases to better articulate the underlying drivers and customer benefits for these investments and have resubmitted them for the AER's consideration (see section 5.5.1).

The AER also did not accept our proposed forecast capex for improving the resilience of our network. The AER recognised the merits of the bushfire and flood program but did not support our mobile substation and mobile generation proposals.[27] We accept the AER's Draft Decision on resilience capex.

3.2.3 Investment priority 3: Facilitate customer opportunities in the transition to renewable energies

Our Regulatory Proposal highlighted that the transition to a net zero emissions future and increasing solar generation has meant that Energex 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 customers' electricity appliances and the network. We therefore proposed 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. These solutions include changing network tariffs to encourage greater energy use by our customers during periods of high solar generation that leads to exporting into the network, expanding our demand management program, and dynamic operation of the network to manage distributed energy resources more efficiently and limit the need for network investment.

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[25] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 8.

[26] Ibid, pp. 14-19.

[27] Ibid, pp. 30-32.

While Energex remains committed to providing opportunities for customers to benefit from the transition to renewable energy and more options to better manage their energy costs through network tariff reform, the AER's Draft Decision did not approve our proposed TSS for the 2025-30 regulatory control period. Key elements that were not approved include our proposed new flexible load control tariffs and grid-scale storage tariffs for both low voltage and high voltage customers.[28] Our revised TSS includes modifications to our proposed tariff structures to address issues raised in the AER's Draft Decision and provides further information to enable their acceptance.

Key initiatives that work alongside network tariffs include active device management and dynamic connection arrangements. These tools allow Energex to manage the energy demand more effectively while offering customers cost-saving opportunities, particularly as the penetration of electric vehicles and smart appliances increases across the State.

A dynamic connection is a new connection option for solar PV, battery and electric vehicle charging installations. It allows additional excess energy to be exported at most times, while ensuring a safe and reliable electricity network is maintained at times of congestion as Energex can restrict their imports from or exports to the network at times of high supply or demand via dynamic control. A dynamic connection agreement will allow Energex to offer customers access to the network that differs from the traditional, static "firm" capacity connection. It involves a customer accepting restrictions on their imports from or exports to the network in exchange for receiving a reduction in their network bill that reflects the lower network costs (current or expected) associated with a dynamically controlled service. For our grid-scale battery storage customers, we are offering lower network charges compared to our default tariff in return for Energex controlling generation and load at times of constraints through dynamic connections.

3.2.4 Investment priority 4: Deliver the electricity infrastructure required for the Brisbane 2032 Olympic and Paralympic Games

Brisbane will host the Olympic and Paralympic Games in 2032 and Energex will play an important role in ensuring the lights stay on while the eyes of the world are focused on South East Queensland. In preparing for Brisbane 2032, Energex must invest in the network to support the connection of new and upgraded venues and other infrastructure projects and cater for increased demand on our network infrastructure. Importantly, as most of these works have already been planned, they will provide reliability benefits to residents and businesses in those communities sooner.

The AER's Draft Decision supported our proposal to bring forward certain investments due to the potential impact of Brisbane 2032.[29] Only one investment (a new feeder between Nudgee to Nundah) that will support the Albion venue redevelopment and Athletes' Village was not accepted.[30] However, Brisbane 2032 was not the only driver for this investment. The feeder is also required to support load growth forecast in this area. This investment was not supported in the AER's Draft Decision on that basis due to the AER's differing interpretation of the Safety Net requirements (as discussed in section 3.2.2). Energex has requested that the AER reconsider this business case (refer to section 5.5.1).

We are pleased that the key investments we proposed to deliver the electricity infrastructure required for Brisbane 2032 were supported by the AER.

[28] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025-2030, Attachment 19 – Tariff structure statement,* September 2024, p. 4-5.
[29] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 7.
[30] Ibid, p. 18.

4.

Demand, Energy Delivered and Customer Forecasts

Key messages:

- Our demand, energy delivered and customer forecasts have been recast using the most recent actuals from 2023-24 and other updated inputs, where appropriate.
- The forecast methodologies remain the same as applied for the Regulatory Proposal.
- Our updated system peak demand forecast has resulted in a higher peak demand than forecast in our Regulatory Proposal, driving the need for one additional network capital investment (refer to Chapter 5).
- The remaining updated forecasts have no material impact on our proposed expenditure in this Revised Regulatory Proposal.

4.1 Overview

In our Regulatory Proposal, we provided forecasts for:

- **System peak demand** – a measure of the total volume of electricity required to be available for customers at a single point in time (in MW). System peak demand is used to identify future capacity constraints, a key driver of network augmentation
- **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 adverse impacts on the network (including possible electricity outages) 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 connection capex, and
- **Growth in distributed energy resources** – a projection of growth in the uptake of electric vehicles, solar PV systems and battery energy storage systems. Growth in distributed energy resources is a key driver of our capex program and feeds into our Distributed Energy Resources Integration Strategy.

There has been no change in approach to our forecasting methodologies. However, the forecasts have been updated using the most recent actual data and inputs to ensure that this Revised Regulatory Proposal reflects reasonable expectations of forecast demand, energy delivered and customer numbers.

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 0.8 per cent annually (this is higher than the 0.4 per cent annual growth rate projected in the Regulatory Proposal)
- the increasing penetration of rooftop solar will cause minimum demand for the Energex distribution area to fall by an average of 353 MW annually
- energy delivered will increase by an average of 0.3 per cent annually
- annual average growth in customer numbers will be around 1.2 per cent, approximately in line with expected population growth in South East Queensland
- electric vehicle volumes will increase to between 317,659 units and 627,008 units by 2030 as there is greater choice and cost parity with conventional vehicles
- solar PV capacity uptake is likely to remain strong and is expected to grow by 10.5 per cent annually for the base scenario, and
- battery energy storage systems capacity is expected to increase by 28.2 per cent annually (for the base scenario) as they become more economically viable.

Table 7 provides a comparison of each forecast as presented in the Regulatory Proposal and updated for this Revised Regulatory Proposal.

Table 7: Comparison of forecasts from the Regulatory Proposal and Revised Regulatory Proposal

Forecast	Regulatory Proposal	Revised Regulatory Proposal
System peak demand	0.4%	0.8%
Forecast change in minimum demand	-413MW	-353MW
Energy delivered	0.4%	0.3%
Customer numbers	1.3%	1.2%
Electric vehicle volumes	347,700 to 995,793 units	317,659 to 672,008 units
Solar PV	7.8%	10.5%
Battery energy storage systems	27.8%	28.2%

Note: All values represent annual average growth rate, except for electric vehicle volumes which represent the expected increase in units by 2030 and the forecast change in minimum demand represents the amount the minimum demand for the Energex distribution area is predicted to (on average) decrease by each year over the five-year period.

4.2 Demand, energy delivered and customer numbers

The historical data used to support the system peak demand, minimum demand, customer numbers and energy delivered forecasts is provided in Table 8 (with updated actual 2023-24 values) and the forecasts are provided in Table 9. The forecast data was estimated using updated inputs, where available, and the same methodology as used for the Regulatory Proposal.

Our updated system peak demand forecast has resulted in a higher peak demand than forecast in our Regulatory Proposal (0.8 per cent compared to 0.4 per cent annual growth rate), driving the need for one additional network capital investment project (refer to Chapter 5).

Table 8: Historical data

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Recorded peak demand (MW)	4,633	4,814	4,926	5,086	5,070	4,573	5,292	5,228[1]	5,687
Recorded minimum demand (MW)	1,465	1,480	1,489	1,342	971	768	593	237	241
Customer numbers[2]	1,421,522	1,448,247	1,473,805	1,496,317	1,516,198	1,535,400	1,569,750	1,602,119	1,618,370
Energy delivered (GWh)	21,138	21,355	21,262	21,427	21,141	21,206	21,295	21,716	22,364

Notes:
1. Minor update to recorded peak demand (was stated as 5,221 in Regulatory Proposal).
2: Historical customer numbers are as per the relevant Economic Benchmarking Regulatory Information Notice (RIN) (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 financial year. Each NMI has been counted as a separate customer.

Table 9: Forecast data

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
10 PoE forecast peak demand (MW)	5,802	5,871	5,919	5,991	6,011	6,049
50 PoE forecast peak demand (MW)	5,430	5,487	5,526	5,583	5,616	5,652
Forecast minimum demand (MW)	-100	-462	-834	-1,219	-1,585	-1,864
Customer numbers	1,638,343	1,658,594	1,678,004	1,697,474	1,716,888	1,736,169
Energy delivered (GWh)	21,687	21,708	21,738	21,854	21,878	22,065

4.3 Distributed energy resources

Our forecasts for the amount of distributed energy resources (i.e. solar PV, electric vehicles and battery energy storage systems) in the network are updated annually and our most recent forecasts (using the same methodology as used for our Regulatory Proposal) are provided in Table 10.

Table 10: Distributed Energy Resources forecasts by scenario (by calendar year)

	2024	2025	2026	2027	2028	2029	2030	2031
Solar PV								
Fast Scenario (kVA)	3,376,749	3,964,180	4,574,372	5,165,132	5,744,570	6,264,319	6,803,671	7,346,383
Medium Scenario (kVA)	3,376,749	3,914,714	4,415,366	4,933,236	5,470,860	6,002,288	6,460,886	6,802,802
Slow Scenario (kVA)	3,376,749	3,881,023	4,380,978	4,866,439	5,329,717	5,780,193	6,164,206	6,511,333
Electric Vehicles								
Fast Scenario (units)	39,265	69,560	126,319	216,310	342,736	497,839	672,008	858,997
Medium Scenario (units)	39,265	53,349	72,956	101,274	144,766	213,488	317,659	454,699
Slow Scenario (units)	39,265	47,034	55,464	66,048	79,491	98,311	126,248	168,758
Battery energy storage systems								
Fast Scenario (kWh)	156,339	209,975	279,637	385,836	507,684	638,039	780,599	949,980
Medium Scenario (kWh)	156,339	189,502	233,151	318,029	416,268	533,561	655,831	775,061
Slow Scenario (kWh)	156,339	186,233	215,507	270,888	334,934	415,216	496,220	583,759

5.
Capital Expenditure

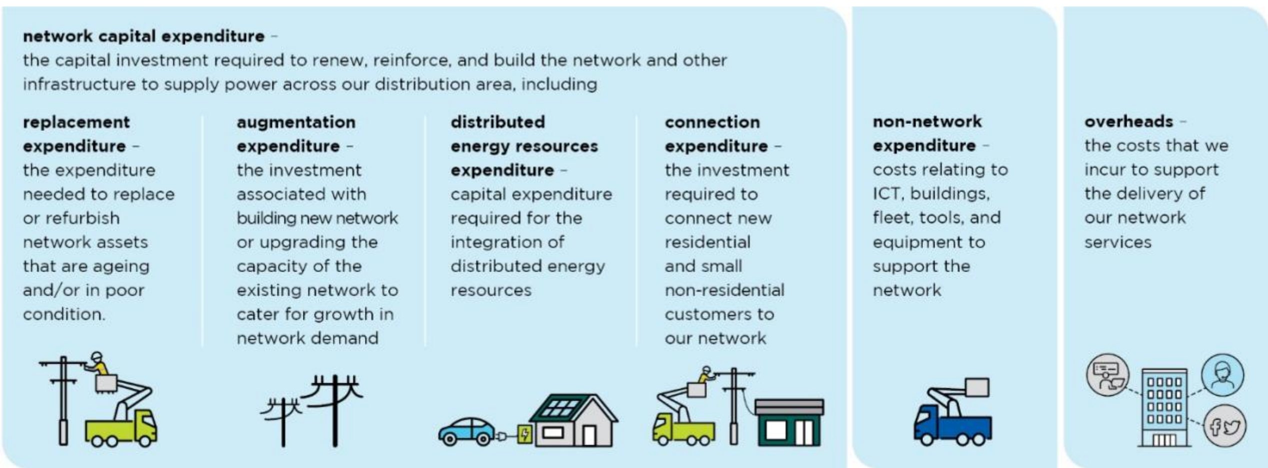
Key messages:

- In its Draft Decision, the AER provided a substitute forecast of $2,801.0 million for Energex capex (including asset disposals and modelling adjustments).
- The AER's Draft Decision accepted our capex forecasts for replacement, connections, distributed energy resources, cyber security, and other non-network (tools and equipment) categories.
- The AER provided a substitute forecast for augmentation, resilience, non-network ICT, property, fleet and capitalised overheads.
- Energex's response to the AER's Draft Decision is to modify our capex forecast of $3,341.1 million with a revised capex forecast of $3,134.7 million (including asset disposals).
- We will modify our augmentation, fleet and capitalised overhead capex forecasts. Our augmentation forecast maintains our interpretation of the Safety Net Targets as set out in the Distribution Authority.
- We will accept the substitute forecasts for the remaining capex categories.

5.1 Overview of the AER's Draft Decision

We remain committed to meeting the expectations of our customers and communities around the reliability, quality, resilience and safety of our network, while meeting the needs of a growing economy and population. To meet these expectations and needs, we require capital investment to build, repair and reinforce the distribution network and other infrastructure to supply electricity to our customers. Our capital investments are categorised as set out in Figure 5.

Figure 5: Capital investment categories



In our Regulatory Proposal, submitted on 31 January 2024, we forecast capex of $3,422.3 million (excluding asset disposals) for the 2025-30 regulatory control period. We subsequently submitted an updated capex model to the AER on 28 June 2024 with an amended forecast of $3,390.8 million (excluding asset disposals). If we include asset disposals, our updated capex forecast was

$3,341.1 million. This value of capex (i.e. including asset disposals) was reported in the AER's Draft Decision.

In its Draft Decision, the AER provided a substitute forecast of $2,801.0 million, which represents a reduction of 16.2 per cent compared to our updated capex forecast.[31] Further detail on the AER's Draft Decision for each capex category is provided in the following sections.

5.2 Our response to the AER's Draft Decision

Energex's response to the AER's Draft Decision is to modify our capex forecast. Our revised capex forecast is $3,134.7 million (including asset disposals) for the 2025-30 regulatory control period, which is a 6.2 per cent reduction to our Regulatory Proposal.

As outlined in the "About this Revised Regulatory Proposal" section of this document, we have adopted the "Accept, Modify and Justify" approach for our Revised Regulatory Proposal. Utilising this approach, our response to the AER's Draft Decision for each category of capex is summarised in Table 11.

Table 11: Summary of our response to AER's Draft Decision on capex

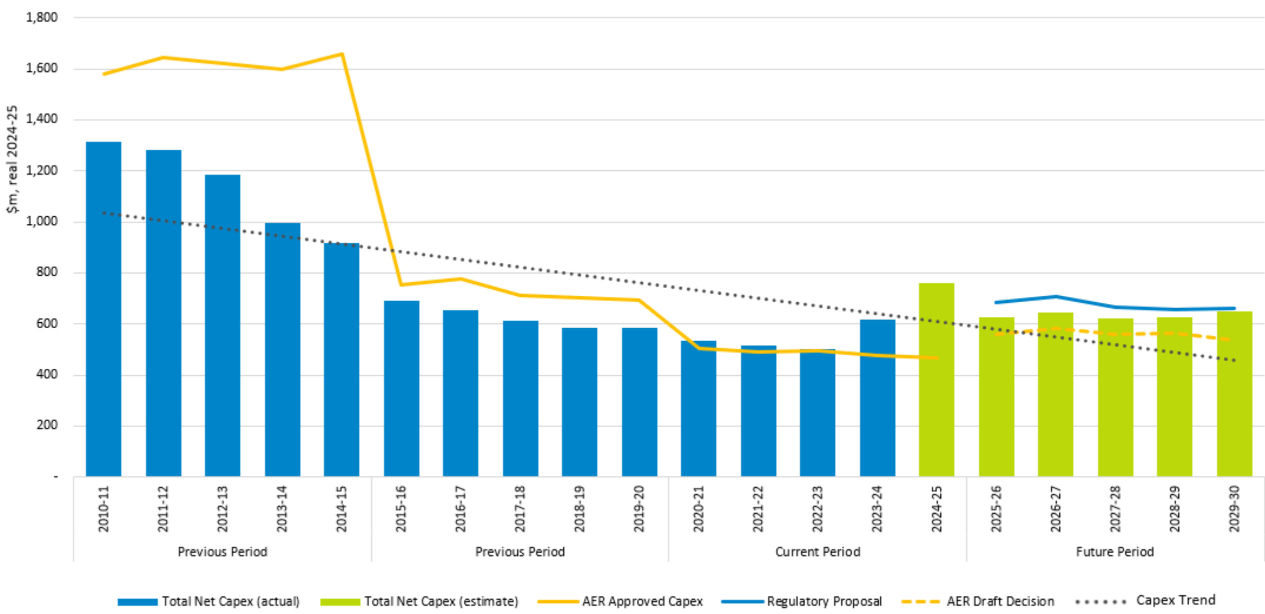
$m, real 2024-25	Regulatory Proposal[1]	Draft Decision	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Replacement	913.2	913.2	0.0	Accept	912.8	-0.4
Augmentation	528.9	324.0	-204.9	Modify	538.6	9.7
Resilience	50.0	25.1	-24.9	Accept	25.1	-24.9
Distributed energy resources	54.1	54.1	0.0	Accept	54.1	0.0
Connections (net)	321.0	321.0	0.0	Accept	320.6	-0.4
Cyber security	48.1	48.1	0.0	Accept	48.1	0.0
Non-network ICT	242.1	195.4	-46.7	Accept	195.2	-46.9
Property[2]	151.9	143.7	-8.2	Accept	143.3	-8.6
Fleet	198.5	168.6	-29.9	Modify	181.6	-16.9
Tools & Equipment	25.2	25.2	0.0	Accept	25.2	0.0
Capitalised overheads	838.1	615.7	-222.4	Modify	720.3	-117.8
Gross Capex[3]	**3,371.2**	**2,834.1**	**-537.1**	**Modify**	**3,164.7**	**-206.5**
Less asset disposals	-30.1	-30.1	0.0	Accept	-30.0	0.1
AER modelling adjustments	0.0	-3.0	N/A			
Net Capex[4]	**3,341.1**	**2,801.0**	**-537.1**	**Modify**	**3,134.7**	**-206.4**

Notes
1. As per updated capex model and includes the AER's re-categorisation of $7.7 million of replacement capex, $16.4 million of augmentation capex and $24.0 million of ICT to cyber security. It also includes the AER's re-categorisation of $50.0 million of augmentation capex to resilience capex.
2. Includes property leases.
3. Totals may not add due to rounding. Does not account for asset disposals.
4. Totals may not add due to rounding.

[31] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 3.

Our proposed capex for the 2025-30 regulatory control period is 8.2 per cent more than our expected spend for the current 2020-25 regulatory control period. As illustrated in Figure 6, our historical capex had been decreasing since 2010 but our forecast capex is slightly above this long-term trend reflecting the need to invest to support strong population and economic growth in South East Queensland.

Figure 6: Capex between 2010 to 2030 ($m, real 2024-25)



We have engaged with the AER on elements of our proposed capex and welcome its feedback. Where applicable, further information on how we have responded to the AER's feedback is provided in the following sections.

5.3 Ex-post review

As we have spent 6 per cent less than the AER's capex forecast for the ex-post review period of 1 July 2018 to 30 June 2023, an ex-post review of our capex is not required. The AER has found that we have "… incurred total capex below our regulatory forecast for the ex-post review period. On this basis, the overspending requirement for an efficiency review of past capex is not satisfied."[32]

5.4 Replacement

We replace and refurbish existing assets that are ageing or in poor condition (e.g. due to rot, termite damage, or general wear and tear) to meet our reliability and safety obligations, and the expectations of our communities.

As outlined in the Regulatory Proposal, our proposed replacement capex for the 2025-30 regulatory control period was in line with our long-term historical average for replacement and represented a continuation of our existing asset management practices.

[32] Ibid, p. 12.

The AER has accepted our forecast of $913.2 million over five years.[33] Our replacement capex is a forecast increase of 7.1 per cent above the current period actual and estimated spend, largely due to investments being brought forward for Brisbane 2032. Our replacement expenditure forecast is also in line with the AER's replacement capex model threshold.[34]

We accept the AER's Draft Decision for replacement capex. After adjusting for updated inflation inputs, our replacement capex forecast is now $912.8 million for the 2025-30 regulatory control period.

5.5 Augmentation

Augmentation capex is the investment associated with building new network or upgrading the capacity of the existing network to cater for growth in network demand. Our response to the AER's Draft Decision on our forecast augmentation capex is summarised in Table 12.

Table 12: Summary of our response to AER's Draft Decision on augmentation

$m, real 2024-25	Regulatory Proposal	Draft Decision[1]	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal[2]	Difference to Regulatory Proposal
Sub-transmission Growth	232.5	59.8	-172.7	Modify	257.5	25.0
• Establish new feeder from Hays Inlet to Narangba	-	-	-	New	25.4	25.4
• AER Rejected Projects (10)	172.6	0.0	-172.6	Justify	172.3	-0.3
• AER Accepted Projects (11)	59.9	59.8	-0.1	Accept	59.8	-0.1
Reliability	27.8	27.8	0.0	Accept	27.8	0.0
Distribution Growth	144.3	144.1	-0.2	Accept	144.2	-0.1
SCADA, Protections and Communications	65.9	62.0	-3.9	Accept	62.1	- 3.8
Clearance	58.4	30.0	-28.4	Modify	46.9	- 11.5
Augmentation Total[3]	**528.9**	**323.7**	**-205.2**	**Modify**	**538.6**	**9.7**

Notes:
1. Values sourced from: AER, *Capex model – Energex distribution determination 2025-30*, September 2024. Minor discrepancies exist between the summation of the disaggregated information in the AER's Capex Model and the aggregated amounts published in the AER's Draft Decision.
2. Minor differences between Draft Decision and Revised Regulatory Proposal values are due to inflation adjustment.
3. Totals may not add due to rounding.

[33] This amount represents the revised replacement capex forecast submitted to the AER on 28 June 2024 and the AER's re-categorisation of $7.7 million to cyber security capex.
[34] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 9.

The AER has not accepted our proposed forecast of $528.9 million[35] over five years and has provided a substitute forecast of $324.0 million.[36] The main reason for a lower substitute forecast is that the AER does not agree with our interpretation of the Safety Net Targets[37] set out in our Distribution Authority and therefore disagrees that these projects are required to comply with our regulatory obligations. This results in a significant reduction in the sub-transmission growth sub-category of our augmentation expenditure.

We propose a revised augmentation forecast (excluding resilience) of $538.6 million for the 2025-30 regulatory control period, an increase of 1.8 per cent from our Regulatory Proposal. This revised forecast reflects our position to:

- modify the sub-transmission growth forecast by:
  - justifying our interpretation of the Safety Net obligation contained in the Distribution Authority (refer to section 5.5.1 for more information). These projects are necessary to ensure that there is sufficient capacity to supply electricity to growing population corridors throughout Greater Brisbane, the Caloundra area in the Sunshine Coast region and Pimpama in the Gold Coast region
  - clarifying the identified need for some projects which the AER appears to have categorised as “Safety Net driven”, but where there were additional or alternative drivers for the expenditure
  - including an additional project to establish a new feeder from Hays Inlet to Narangba due to the increase in our latest load forecast projection undertaken after submission of our Regulatory Proposal (refer to Attachment 5.5.01). This project is based on a positive cost-benefit business case in addition to Safety Net obligations, and caters for continued strong growth in the Caboolture, Burpengary and Morayfield region.
- modify our clearance capex forecast. In its Draft Decision, the AER accepted our forecast volume of clearance issues across the network but had concerns with the unit rates for rectification. We have updated the unit rates and segmented them between major and minor rectification works. We have segmented the unit rates to reflect that many of the clearance to structure defects in Energex’s network are more complex, with bespoke solutions needed that go beyond simple re-tensioning. Horizontal clearance breaches, for instance, often necessitate additional work such as converting low voltage open wire to bundled conductors. We have therefore segmented the unit rates into major and minor categories so that the applicable rate can be applied to the relevant rectification works in our revised business case, improving cost-reflectivity (refer to Attachment 5.5.02)
- accept the AER’s grid communications, protection and control substitute estimate, and
- accept the AER’s approval of Energex’s reliability and distribution growth expenditure.

Table 13 summarises how we have responded to the AER’s feedback.

[35] This amount represents the revised augmentation capex forecast submitted to the AER on 28 June 2024 and the AER’s re-categorisation of $50.0 million to resilience capex and $16.4 million to cyber security capex.

[36] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 13.

[37] The Safety Net Targets set out how quickly load not supplied is to be restored following an N-1 event.

Table 13: How we have responded to AER's Draft Decision on augmentation capex

Issue in Draft Decision	Our response	More information
Sub transmission growth		
Interpretation of Safety Net obligations	We have included the original suite of Safety Net driven projects in our Revised Regulatory Proposal and further information justifying our interpretation of the Safety Net obligation.	Section 5.5.1 outlines our position.
Clearance		
Lack of supporting evidence to justify unit rates	We have updated the unit rates and segmented them between major and minor rectification works.	A revised business case has been included.
Grid communications, protection and control		
Concerns regarding benefits for the OTE Zetron Continuous Improvement project	We accept the AER's Draft Decision to remove this project.	N/A
Deliverability concerns for the DC and Bus Overcurrent Protection Duplication program	We accept the AER's Draft Decision to remove the five smallest projects (of 29 projects) from this program.	N/A

Refer to section 5.13 for a list of business cases (revised and new) for our proposed investments for augmentation capex.

5.5.1 Safety Net driven projects

Safety Net interpretation

In its Draft Decision, the AER outlined that it has a different interpretation of the Safety Net obligation that is part of our Distribution Authority. The Distribution Authority states that the purpose of the Safety Net is "to seek to effectively mitigate the risk of low probability - high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption".[38] In this way, its intention is to ensure that all customers have a consistent, basic level of network reliability.

In correspondence with the AER, we were provided with a table that shows a comparison of our interpretation and the AER's interpretation of the Safety Net obligations. Table 14 shows the difference in interpretation between the AER and Energex for the urban customer Safety Net obligations.

[38] *Distribution Authority – No. D07/98 – ENERGEX Limited,* clause 10.1, available on the Department of Energy and Climate website.

Table 14: Interpretation of Urban Customer Safety Net obligations

Range of load unsupplied	Energex interpretation of restoration time	AER interpretation of restoration time
Greater than 40MVA	No time specified[1]	30 minutes to reduce the load unsupplied to 40MVA or lower
40MVA to greater than 12MVA	30 minutes to reduce the load unsupplied to 12MVA or lower	3 hours to reduce the load unsupplied to 12MVA or lower
12MVA to greater than 4MVA	3 hours to reduce the load unsupplied to 4MVA or lower	8 hours to reduce the load unsupplied to 4MVA or lower
Less than or equal to 4 MVA	8 hours to have supply to all load restored	No time requirement to restore supply – can be without supply for more than 8 hours

Note 1: From Energex's perspective "no time specified" means that it is not permitted to have any load unsupplied above 40MVA under any circumstances.

As Table 14 outlines, the AER's interpretation appears to imply there would be no limit to the number of customers that could be immediately left unsupplied following an outage of a single item of plant. Furthermore, it does not include a restoration timeframe for the last remaining 4 MVA, and therefore there is no maximum timeframe to fully restore supply. In our view, this does not align with the intent of the Safety Net Targets, which is to provide a base level of reliability for all customers.

Since the introduction of the Safety Net Targets in 2014, Energex has reported on and engaged extensively with customers on its interpretation. Section 5 of our Distribution Annual Planning Report (DAPR) outlines our Network Planning Framework and describes the application of the Safety Net and its interaction with probabilistic planning.[39] Energex's description of the application of the Safety Net in the DAPR has not changed across this time. Since 2014, we have also conducted 20 Regulatory Investment Test for Distribution consultations under our interpretation of the Safety Net.

When presented with the AER's Draft Decision on our investment for Safety Net, the VOC Panel voiced strong support for the inclusion of these projects in forecast expenditure to cater for future growth in South East Queensland. The VOC Panel made it clear that they expected current network reliability performance to be maintained.

Prior to the Draft Decision, we provided our interpretation of the Safety Net provisions to the Queensland Department of Energy and Climate who supported our interpretation. Given that the Queensland Government has supported our interpretation, and that we have been operating under this interpretation since 2014, we respectfully submit that the resultant projects that form part of our augmentation capex submission are required to meet this Distribution Authority obligation and ensure we are compliant with our regulatory obligations.

[39] Energex, *Distribution Annual Planning Report*, 2023, p. 48.

Safety Net Projects Cost-Benefit Analysis

In its Draft Decision, the AER noted that "Energex has not provided a cost-benefit analysis (CBA) for these projects or any alternative justification for this expenditure".[40] On 18 June 2024, we provided the AER with business cases showing that the New Ripley North Zone Substation and New Morayfield East Zone Substation project had a positive cost-benefit analysis, in addition to being required to meet our regulatory obligations under the Safety Net Targets.

Our Safety Net obligations are also not the primary driver for the New Bells Creek Zone Substation project. Instead, the primary driver for investment is the requirement to connect new customers in a new residential development. One option we considered was to build long feeders from Caloundra Zone Substation to connect these new customers, which was Option 2 in the business case. However, as more and more customers connect, we will not be able to continue to economically build these feeders as space in the road verge becomes constrained. The provision of a substation close to the load centre removes the need to build these feeders and forms the basis of the timing and requirement for the substation. For improved clarity, we have provided an updated justification and re-framed cost-benefit analysis demonstrating the need for this substation irrespective of the Safety Net obligations (refer to Attachment 5.5.03).

In addition, this Revised Regulatory Proposal includes a cost-benefit analysis for the Upgrade 33kV Feeder Capacity for F341 from Gympie to Tin Can Bay project in addition to its Safety Net obligation drivers (refer to Attachment 5.5.04).

Consequences of Safety Net Projects not proceeding

The investments categorised as "Safety Net driven" are also necessary as they enable Energex to fulfil its obligations to connect customers to the network in fast growing areas of South East Queensland. Establishing Ripley North, Morayfield East, Jimboomba West and Bells Creek Central Zone Substations results in Energex also being able to connect customers in these areas to feeders that are shorter than would otherwise be the case. Were these projects not to proceed, Energex would be required to provide a sub-optimal solution to supply these new customers from the closest adjacent substations that would provide a lower level of reliability. This would include establishing the following:

- **Ripley North** – new feeder from Cooneana Zone Substation
- **Morayfield East –** new feeder from Morayfield North Zone Substation
- **Jimboomba West –** new feeder from North Maclean Zone Substation, and
- **Bells Creek Central –** new feeder from Caloundra Zone Substation.

5.6 Resilience

The AER assessed our resilience capex separately for its Draft Decision. The resilience investment we proposed was initially included in our augmentation capex forecast and has been re-categorised into a stand-alone resilience capex category by the AER.

The AER provided a substitute forecast of $25.1 million over five years. The AER recognised the merits of the bushfire and flood program but did not support our mobile substation and mobile generation proposals.[41]

[40] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 18.
[41] Ibid, p. 9.

We accept the AER's Draft Decision for resilience capex. After adjusting for updated inflation inputs, our resilience capex forecast is now $25.1 million for the 2025-30 regulatory control period.

5.7 Distributed energy resources

Distributed energy resources is a new category of expenditure for the 2025-30 regulatory control period. This category of expenditure relates to augmentation of the network to resolve constraints associated with incorporating distributed energy resources that export energy into the distribution network. This could include exports from rooftop solar, battery storage or electric vehicles with vehicle-to-grid capability.

The AER accepted our distributed energy resources-related capex proposal of $54.1 million over five years. The AER found that our strategy was generally sound and measured and was supportive of our approach to prioritising dynamic connection investments over increasing hosting capacity.[42]

We accept the AER's Draft Decision for distributed energy resource-related capex. After adjusting for updated inflation inputs, our distributed energy resources-related capex forecast is now $54.1 million for the 2025-30 regulatory control period.

5.8 Connections

Net connection expenditure is the investment required to connect new residential and small business customers to our distribution network. Population growth drives the volume of new home and business customer connections. As outlined in our Regulatory Proposal, population growth in South East Queensland has been strong since the Covid-19 pandemic due to greater migration, smaller household sizes, increasing construction expenditure forecasts and a growing economy.

The AER accepted our net connection capex proposal of $321.0 million over five years.[43] The AER was satisfied with our proposal based on its own trend analysis of past connections expenditure.[44]

We accept the AER's Draft Decision for net connection capex. After adjusting for updated inflation inputs, our connections-related capex forecast is now $320.6 million for the 2025-30 regulatory control period.

5.9 Cyber security

Energex and other critical infrastructure service providers face growing cyber threats due to more connectivity, increased adoption of big data and cyber-physical assets, and greater digitalisation and automation. Investing in cyber security helps to protect our network and data from cyber security threats, such as ransomware or malicious critical infrastructure attacks.

The AER has assessed our cyber security capex as a stand-alone category for its Draft Decision.

In our Regulatory Proposal, the funding proposal for cyber security was contained within one business case, but the funding was split into three categories – replacement ($7.7 million), augmentation ($16.4 million) and non-network ICT ($24.0 million).

[42] Ibid, pp. 9-10.

[43] This amount represents the net connections capex forecast corrected for a modelling error and resubmitted to the AER on 28 June 2024.

[44] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 9.

The AER has accepted our total cyber security forecast of $48.1 million over five years as it found that the information provided adequately supported the proposal and that we had a good understanding of our compliance obligations.[45]

We accept the AER's Draft Decision for cyber security capex. After adjusting for updated inflation inputs, our cyber security capex forecast is now $48.1 million for the 2025-30 regulatory control period.

5.10 Information, communications and technology

Our non-network ICT investments focus on ensuring that our systems are maintained for sustainability, compliance and operational safety and security, while keeping pace with the expected industry transition to a more connected, digitalised environment.

The AER has provided a substitute forecast of $195.4 million over five years for non-network ICT capex (excluding cyber security). We note the AER's feedback on our business cases and the AER's conclusion that the "maintain" base case option is prudent and efficient.[46]

We appreciate the AER's openness to engaging with us and have met with the AER to discuss their feedback and some of the challenges all DNSP's face in preparing digital business cases in a rapidly changing technological environment.

We remain of the view that our proposed expenditure is necessary to keep pace with the growing digitalisation and ever-changing customer expectations of the electricity industry. However, given the complexity of dependencies between investments enabling benefits and business units realising benefits, as well as the business priority in responding to other aspects of the Draft Decision, we will accept the AER's Draft Decision for non-network ICT capex.

After adjusting for updated inflation inputs, our non-network ICT capex forecast is now $195.2 million for the 2025-30 regulatory control period.

5.11 Other non-network

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 three categories of support costs: property (including capitalised leases), fleet, and tools and equipment.

The AER's Draft Decision for these support costs was to:

- provide a substitute forecast for our non-network property expenditure of $143.7 million over five years (a 5 per cent reduction from our Regulatory Proposal forecast)[47]
- adjust our fleet forecast of $198.5 million to $168.6 million over five years based on accepting the base case for the elevating work platform (EWP) and crane borer business cases, along with the removal of the full-time equivalent (FTE) uplift based on adjustments made to the network capex forecasts,[48] and
- accept our tools and equipment forecast of $25.2 million over five years.[49]

[45] Ibid, p. 9.
[46] Ibid, p. 10.
[47] Ibid, p. 11.
[48] Ibid, p. 11.
[49] Ibid, p. 10.

We accept the AER's Draft Decision on our property (including capitalised leases), and tools and equipment forecasts.

For our fleet forecast, we accept the AER's Draft Decision to remove the expenditure forecast related to the FTE uplift. However, we are requesting additional capex of $13.0 million above the Draft Decision to reflect our preferred replacement strategy for both EWPs and crane borers (refer to Table 15). The capex forecast which has been included for this strategy is equivalent to our Regulatory Proposal.

Table 15: Summary of our response to AER's Draft Decision on other non-network capex

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Our Response	Revised Regulatory Proposal[1]	Difference to Regulatory Proposal
Property (including capitalised leases)	151.9	143.7	-8.2	Accept	143.3	-8.6
Fleet	198.5	168.6	-29.9	Modify	181.6	-16.9
Tools and equipment	25.2	25.2	0.0	Accept	25.2	0.0
Other Non-network Total[2]	**375.6**	**337.5**	**-38.1**	**Modify**	**350.1**	**-25.5**

Notes
1. Minor differences between Draft Decision and Revised Regulatory Proposal values are due to inflation adjustment.
2. Totals may not add due to rounding.

Table 16 summarises how we have responded to feedback from the AER and customers.

Table 16: How we have responded to AER's Draft Decision on other non-network capex

Issue in Draft Decision	Our response	More information
Fleet Base case approved for EWP and crane borers due to lack of evidence to support the downtime benefits used in the net present value (NPV) calculation.	We acknowledge the lack of detailed evidence provided to support our downtime benefit calculation. For the EWP assets, the datasets which were used to calculate the number of days downtime and the cost per day have now been included as supporting information in Appendix 4 of the business case. For the crane borer assets, this business case did not use the downtime benefit for aged truck assets. We consider that the preferred option is the most prudent and efficient option, as it has the lowest NPV and is justified solely on it having the most efficient long-term operating and capital costs.	Refer to Attachments 5.11.01 (EWP) and 5.11.02 (Crane Borer)
Fleet Removal of FTE uplift based on wider reductions to the total network capex forecast.	We accept the AER's Draft Decision and have removed the forecast related to the FTE uplift over the 2025-30 regulatory control period.	N/A

Issue in Draft Decision	Our response	More information
Property Base case approved for Rocklea Training Facility due to revenue benefits being included from ACS.	After reviewing the AER's feedback, we acknowledge that we have different views around how the benefits of training revenue are included. Given that we have already included our position in a response to an information request and have no further quantification, we will accept the AER's Draft Decision for non-network property.	N/A

5.12 Capitalised overheads

Overheads are business support costs that we incur in delivering network services to customers (e.g. costs related to finance, human resources or indirect costs incurred to operate and maintain vehicles or property). We capitalise some of our overheads (i.e. include them in capex) in accordance with our Cost Allocation Methodology (CAM) and capitalisation policies, as well as accounting standards requirements.

The AER's Draft Decision for these support costs was to provide a substitute estimate of $615.7 million over five years based on its standard methodology and apply our proposed annual 1.0 per cent efficiency adjustment. The AER's methodology uses the available actual capex and overheads from the current regulatory control period, which is typically three years for a draft decision and four years for a final decision.[50] In our Regulatory Proposal, we estimated our capitalised overheads using a bottom-up build based on the most recent year of actual capex and overheads (which was 2022-23).

We accept the use of the AER's methodology and have recalculated our capitalised overheads using the most recent actual capex and overheads inputs. In line with our opex, we have applied an efficiency adjustment of 1.0 per cent to these costs. Our capitalised overheads forecast for the 2025-30 regulatory control period is $720.3 million.

5.13 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Our Response to the AER's Draft Decision		
Energex SCS Capex Model	5.2.01	Energex - 5.2.01 - SCS Capex model - November 2024 - public
Response to Reset RIN 4.4.4 and 4.4.5 Capex Transparency	5.2.02	Energex - 5.2.02 - Response to Reset RIN 4.4.4 and 4.4.5 Capex Transparency - November 2024 - public
Augmentation		
Business Case, NPV Model and Risk Quantification – Establish new feeder HIL-NRA	5.5.01	Energex - 5.5.01A - Business Case - Establish new feeder HIL-NRA - November 2024 - public Energex - 5.5.01B - NPV Model - Establish new feeder HIL-NRA - November 2024 - public Energex - 5.5.01C - Risk Quantification - Establish new feeder HIL-NRA - November 2024 - public
Business Case – Clearance to Ground and Structure	5.5.02	Energex - 5.5.02 - Business Case - Clearance to Ground and Structure - November 2024 - public

[50] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 5 – Capital expenditure*, September 2024, p. 39-40.

Augmentation		
Memorandum – Bells Creek Central	5.5.03	Energex - 5.5.03 - Memo Bells Creek Central RRP - November 2024 - public
Business Case – Upgrade 33kV Feeder Capacity for F341 from Gympie to Tin Can Bay	5.5.04	Energex - 5.5.04A - Business Case - Upgrade 33kV Feeder Capacity for F341 from Gympie to Tin Can Bay - November 2024 - public Energex - 5.5.04B - NPV Model - Upgrade 33kV Feeder Capacity for F341 from Gympie to Tin Can Bay - November 2024 - public Energex - 5.5.04C - Risk Quantification - Upgrade 33kV Feeder Capacity for F341 from Gympie to Tin Can Bay - November 2024 - public
Other non-network		
Business Case and NPV model – EWP Replacement	5.11.01	Energex - 5.11.01A - Business Case Non-Network Fleet - EWP Replacement - November 2024 - public Energex - 5.11.01A - Business Case Non-Network Fleet - EWP Replacement - November 2024 - confidential Energex - 5.11.01B - NPV Model Non-Network Fleet - EWP Replacement - November 2024 - confidential
Business case and NPV model – Crane Borer Replacement	5.11.02	Energex - 5.11.02A - Business Case Non-Network Fleet - Crane Borer Replacement - January 2024 - public Energex - 5.11.02A - Business Case Non-Network Fleet - Crane Borer Replacement - January 2024 - confidential Energex - 5.11.02B - NPV Model Non-Network Fleet - Crane Borer Replacement - January 2024 - confidential
Non-network Fleet forecast replacement model	5.11.03	Energex - 5.11.03 - Non-network Fleet forecast replacement model - November 2024 - confidential
Capitalised overheads		
Capitalised Corporate Overhead Calculations Model	5.12.01	Energex - 5.12.01 - Capitalised Corporate Overhead Calculations - November 2024 - public

6.
Operating Expenditure

Key messages:

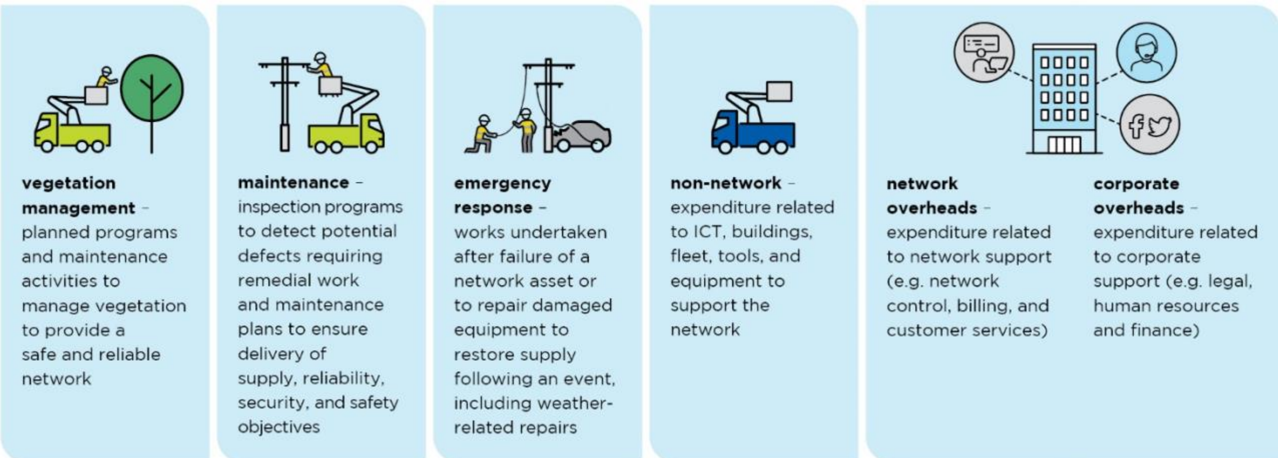
- Our customers expect Energex to continue to affordably deliver a safe, secure and reliable network.
- In the Regulatory Proposal, we forecast opex for the 2025-30 regulatory control period of $2,284.9 million (including debt raising costs). The AER accepted this forecast.
- Our Regulatory Proposal was based on a forecast 2023-24 base year. Our base year opex has been updated to reflect actual data for 2023-24.
- We have made an efficiency adjustment to the base year, applied a 1.0 per cent annual productivity factor to apply over the 2025-30 regulatory control period and included only one step change.
- Our forecast opex to meet customers' expectations for the 2025-30 regulatory control period is now $2,510.2 million, a 9.9 per cent increase on our Regulatory Proposal and the AER's Draft Decision.
- Our opex forecast is one of the building blocks that form part of our revenue requirement.

6.1 Overview

We incur costs to operate and maintain our network to meet the everyday performance and service needs of our customers and communities, including meeting expectations around keeping our network safe, reliable and secure, while ensuring that we do so as efficiently as possible. Customers also rely on us to restore power supply as quickly as possible following severe weather events and natural disasters.

Our opex is a key building block of our annual revenue requirement, and costs are recovered on an annual basis. This expenditure is broken down into the high-level categories set out in Figure 7.

Figure 7: Opex categories



6.2 Our response to the AER's Draft Decision

In our Regulatory Proposal we forecast opex of $2,284.9 million (inclusive of debt raising costs) for the 2025-30 regulatory control period. In its Draft Decision, the AER calculated an alternative estimate of $2,363.8 million (3.5 per cent higher than our Regulatory Proposal). The AER therefore accepted our proposed forecast but noted that we would provide actual opex for 2023-24 for consideration in the Final Decision.[51]

Our Regulatory Proposal was based on a forecast 2023-24 base year. We have updated our data to reflect actual 2023-24 costs and the most recent information for other model inputs. Our revised forecast opex is $2,510.2 million for the 2025-30 regulatory control period. This represents an increase of 9.9 per cent relative to our Regulatory Proposal and the AER's Draft Decision. We consider this level of opex is required to carry out the activities outlined in Figure 7 to achieve the opex objectives listed in clause 6.5.6 of the NER.

Our response to the AER's Draft Decision on our forecast opex is summarised in Table 17 and Figure 8.

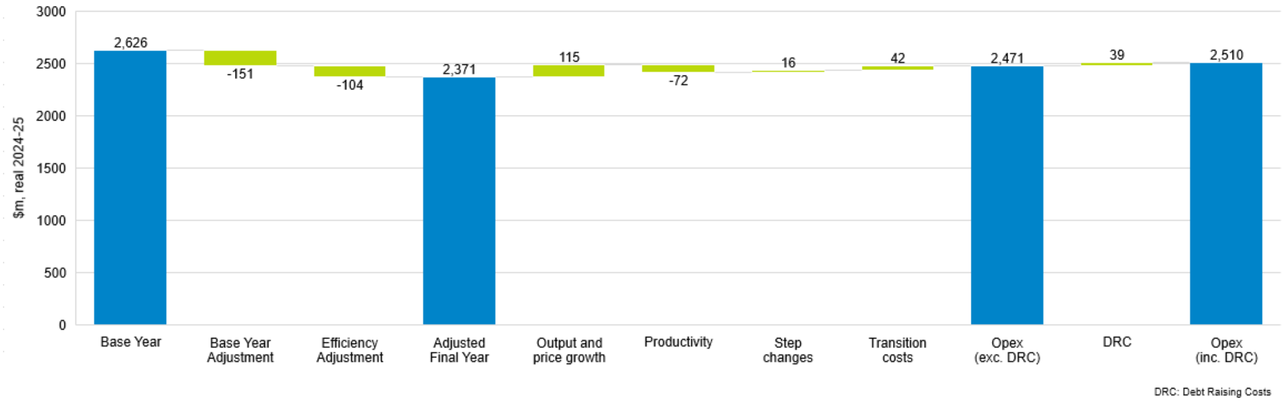
Table 17: Summary of our response to AER's Draft Decision on opex

$m, real 2024-25	Regulatory Proposal	AER alternative estimate[1]	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Base opex	2,474.0	2,469.4	-4.6	Modify	2,626.2	152.3
Efficiency adjustments	-138.9	-122.5	16.4	Modify	-104.4	34.5
Transition costs	0.0	50.1	50.1	Modify	42.3	42.3
Base year adjustments	-101.7	-101.7	0.0	Modify	-98.1	3.5
2023-24 to 2024-25 increment	-12.7	-12.8	-0.1	Modify	-12.8	-0.1
Remove debt raising costs	-32.4	-32.3	0.1	Modify	-40.3	-7.9
Trend: Price growth	49.4	44.9	-4.5	Modify	45.1	-5.7
Trend: Output growth	58.8	59.9	1.1	Modify	69.8	13.0
Trend: Productivity growth	-65.6	-33.2	32.4	Modify	-72.3	-4.6
Step changes	14.6	3.4	-11.2	Modify	15.7	1.1
Total opex excl DRC	**2,245.5**	**2,325.2**	**79.7**	**Modify**	**2,471.2**	**225.7**
Debt raising costs	39.3	38.7	-0.6	Modify	39.0	-0.3
Total[2]	**2,284.9**	**2,363.9**	**79.1**	**Modify**	**2510.2**	**225.4**

Notes:
1. As the AER's alternative estimate was higher than Energex's Regulatory Proposal, the AER accepted the proposal of $2,284.9 million.
2. Totals may not add due to rounding.

[51] AER, *Draft Decision, Energex Distribution Determination 2025 to 2030, Overview*, September 2024, pp. 15-16.

Figure 8: Components of Forecast Opex 2025-30 ($m, real 2024-25)



Whilst approving the opex included in our Regulatory Proposal, the AER included feedback on the approach for some components or requested further information be provided in the Revised Regulatory Proposal. Table 18 sets out how we have responded to the AER's feedback in the Draft Decision and where to find more information.

Table 18: How we have responded to AER's Draft Decision on opex

Issue in Draft Decision	Our response	More information
Engagement Lack of genuine engagement on opex forecasts.	We acknowledge the limited scope for engagement on opex forecasts. This is, in part, due to the lack of ability to influence outcomes as a result of using a standardised base-step-trend model. We discussed our approach to the acquisition of smart meter data with our RRG, who provided feedback that investment should be based on the highest net benefit option. We also discussed our proposed higher 1.0 per cent productivity factor with the RRG in our engagement on the Draft Plans, and engagement with the Customer and Community Council and VOC Panels.	N/A
Productivity Encouraged to consider how we will achieve productivity savings and provide this detail in revised proposal.	The reductions in opex due to the efficiency adjustment and the productivity factor 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.	Further detail on how Energex is proposing to achieve efficiencies in the 2025-30 regulatory control period is included in Attachment 6.05.
Base year Consider if 2023-24 is an appropriate choice of base year.	The base year 2023-24 has been selected as it represents the most recent year for which actual audited data is available.	Section 6.4.1
Operating environment factors Seeking network overheads data separated into amounts expensed and capitalised based on the current CAM.	We engaged with the AER on the request for this information in October 2024. The AER was provided with the network overheads data required for the purposes of sensitivity testing.	N/A

Issue in Draft Decision	Our response	More information
Step changes Not satisfied that Energex has demonstrated that the costs associated with purchasing near real-time meter data are prudent and efficient. Did not provide supporting information to demonstrate key benefit assumptions.	We have updated the business case and cost-benefit analysis to incorporate the AER's and Energy Market Consulting associates' (EMCa's) feedback, the Australian Energy Market Commission's (AEMC's) final decision on meter data acquisition and our latest results from the trials we are undertaking on smart meter data.	Attachment 6.04

6.3 Our proposed opex for 2025-30

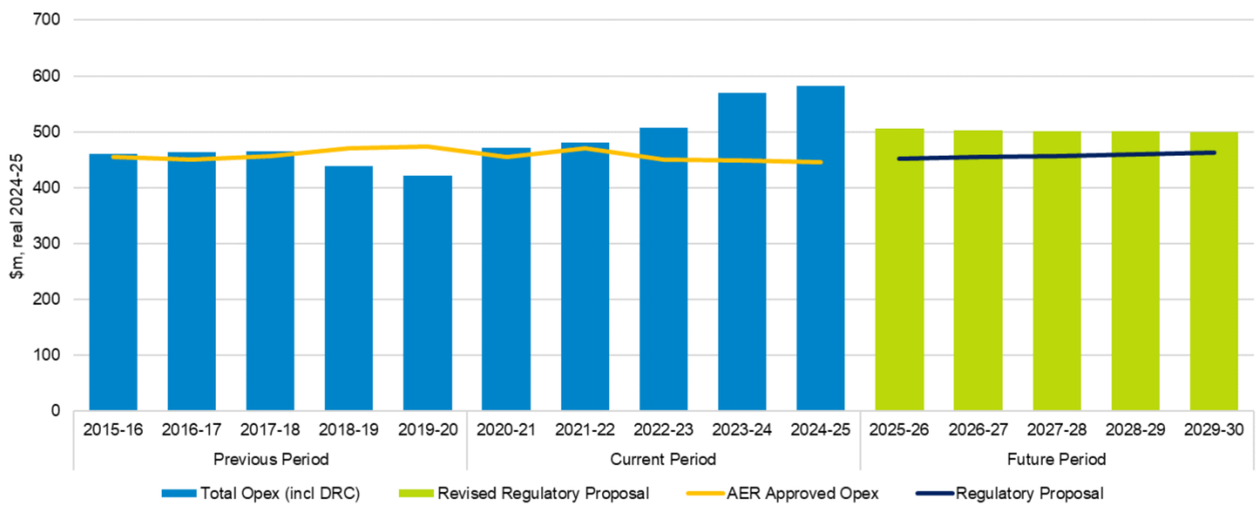
Our revised opex forecast of $2,510.2 million for the 2025-30 regulatory control period is set out in Table 19. This represents a decrease of 3.9 per cent relative to our actual/forecast opex for the current regulatory control period and is in line with historical opex (refer to Figure 9).

Table 19: Forecast opex 2025-30

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Opex (excl. debt raising costs)	498.0	495.4	493.6	492.6	491.6	**2,471.2**
Debt raising costs	7.8	7.8	7.8	7.8	7.8	**39.0**
Total opex[1]	**505.8**	**503.2**	**501.4**	**500.4**	**499.4**	**2,510.2**

Note 1: Totals may not add due to rounding.

Figure 9: Opex between 2015 to 2030



6.4 Our forecasting approach

Consistent with our Regulatory Proposal, Energex has applied a base-step-trend methodology to calculate the majority of the opex forecast in our Revised Regulatory Proposal. 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 10.

Figure 10: Approach to forecasting opex

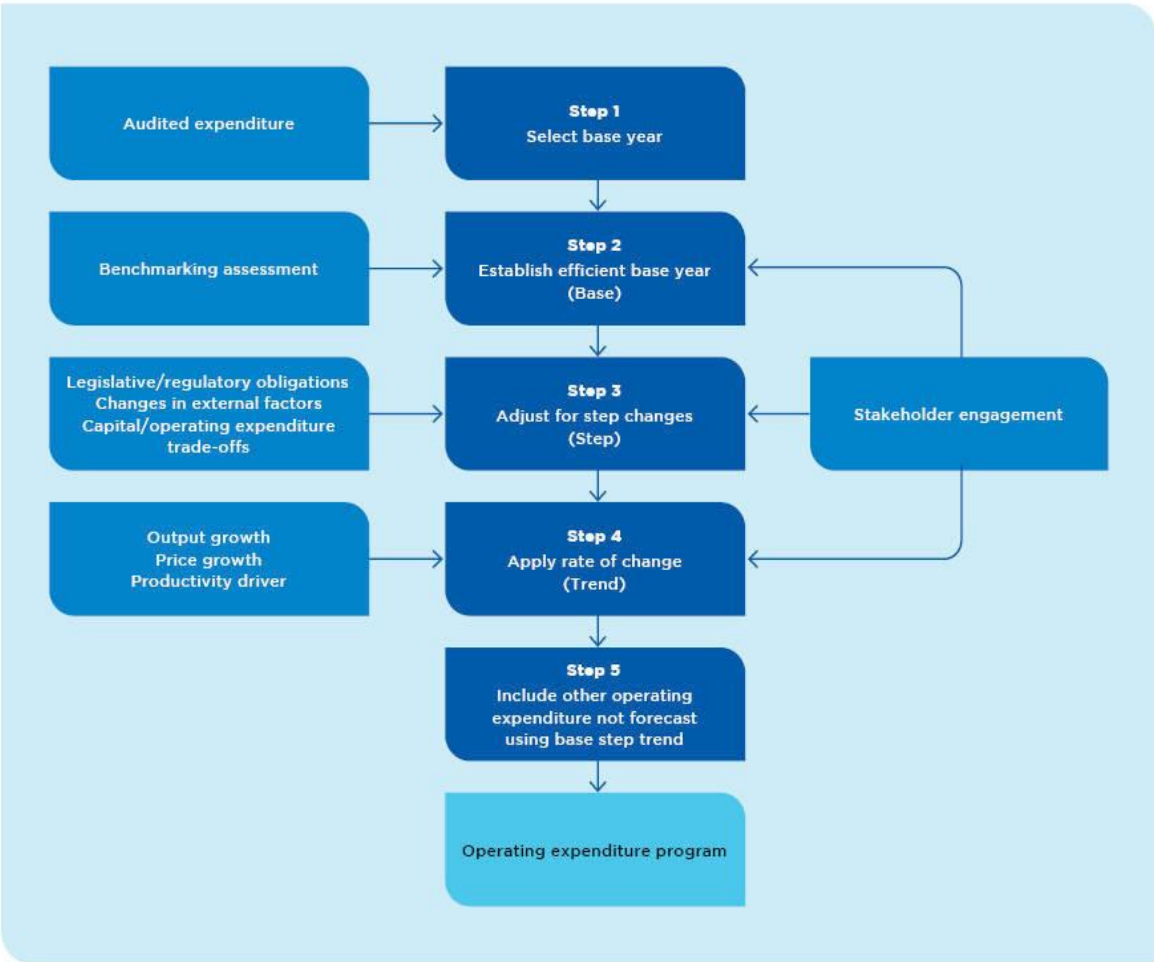


Table 20 outlines the key components of the base-step-trend approach and how each component differs from our initial proposal and the AER's alternative estimate in its Draft Decision.

Table 20: Key components of the opex forecast for 2025 to 2030

Component	Regulatory Proposal	AER Alternative Estimate	Revised Regulatory Proposal
Base opex and efficiency	We selected a base year of 2023-24 and used forecast data as the basis. We tested the base year for efficiency using the *2023 Annual Benchmarking Report* and applied a 5.9 per cent efficiency adjustment.	The AER used our forecast data for 2023-24 as the base year. The AER tested the base year using the *2023 Annual Benchmarking Report*, with some revisions for updated data, and applied a 5.2 per cent efficiency adjustment.	We have used our actual data for 2023-24 as the base year. We tested our actual base year for efficiency using the preliminary results of the *2024 Annual Benchmarking Report*. The raw efficiency adjustment is estimated at 11.5 per cent. We have removed some costs (for extreme weather events and provisions) to arrive at an efficiency adjustment of 4.2 per cent. Additional information is included in section 6.4.1.
Transition costs	We did not include transition costs in our Regulatory Proposal.	The AER included $50.1 million for transition costs in its alternative estimate.	We have included $42.3 million in transition costs in our Revised Regulatory Proposal based on our updated 2023/24 base year costs.
Base year adjustments	Adjustments to the base year were made to remove costs such as the Electrical Safety Office (ESO) levy ($13.7 million) (which will be treated as a jurisdictional scheme)[52] and property leases ($6.7 million) (which will be treated as capex).[53]	The AER applied the same base year adjustments as our proposal.	We have applied adjustments for the ESO levy (actual $14.5 million) and property leases (actual $5.1 million).
Step changes	A step change of $14.6 million was included for smart meter data, representing a new cost that will be incurred during the period.	The AER substituted our step change with costs of $3.4 million.	We have updated our smart meter data business case and have included a step change of $15.7 million. Additional information is included in section 6.4.2.

[52] The ESO levy has been reclassified as a Jurisdictional Scheme, effective 1 July 2025 and therefore is no longer funded through the opex allowance. Instead, the levy costs will be funded through Jurisdictional Scheme charges.
[53] 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, Energex will adopt this change from 1 July 2025.

Component	Regulatory Proposal	AER Alternative Estimate	Revised Regulatory Proposal
Rate of change	We trended the base year forward to reflect changes in outputs, prices and productivity. A productivity rate of 1.0 per cent per annum was applied.	The AER trended the base year forward to reflect changes in outputs, prices, and productivity. A productivity rate of 0.5 per cent per annum was applied.	We trended the base year forward to reflect changes in outputs, prices and productivity. A productivity rate of 1.0 per cent per annum was applied. Additional information is included in section 6.4.3.
Other opex	We included $39.3 million in debt raising costs which were forecast using the AER's benchmark method.	The AER included $38.7 million in debt raising costs which were forecast using the AER's benchmark method.	We included $39.0 million in debt raising costs which were forecast using the AER's benchmark method. The calculation of our debt raising costs is set out in the PTRM (Attachment 8.03).

6.4.1 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 as the 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.

We are unable to use 2022-23 as a base year as it does not provide a realistic expectation of on-going costs. The 2022-23 year does not include the full increase in external contractor costs, general inflationary increases and internal labour costs which we have experienced recently. We anticipate our ongoing annual opex to provide SCS services over the 2025-30 regulatory control period to be higher than this level. In addition, we are unable to use 2024-25 as a base year as audited data will not be available at the time of the Final Decision.

As previously discussed, our Regulatory Proposal was prepared using a forecast 2023-24 base year. Since the submission of our Regulatory Proposal our costs have increased. These increases are due to both internal factors (including labour costs and FTE increases) and external factors (including general inflationary pressure, contractor costs and extreme weather events). We have used actual base year opex of $544.1 million ($2023-24) in our Revised Regulatory Proposal.

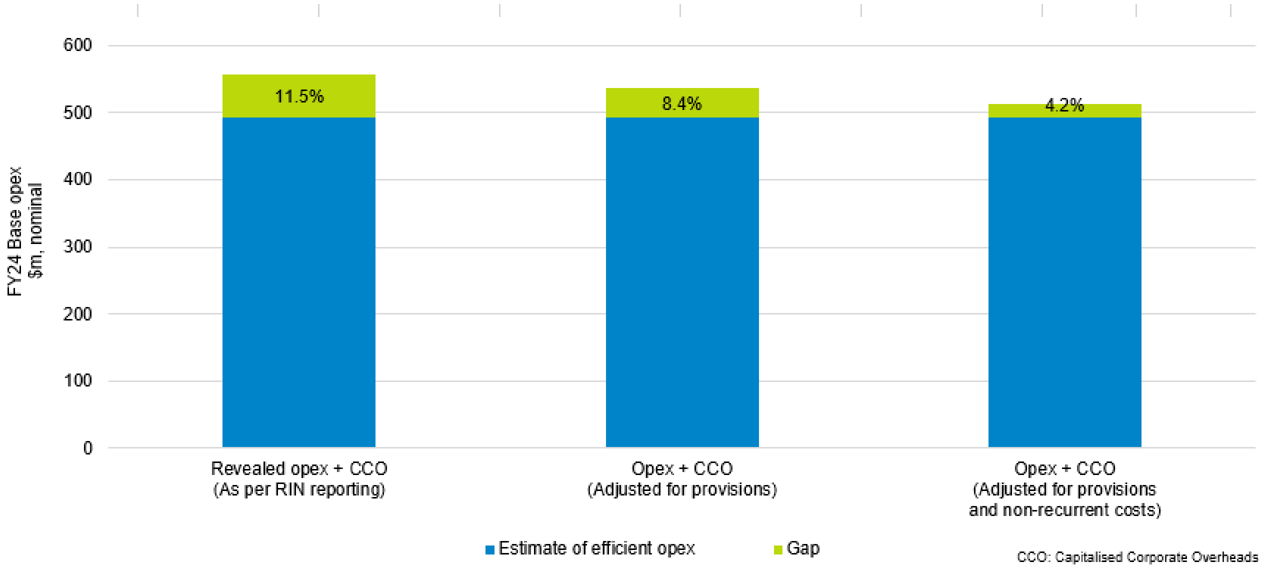
The AER is expected to release its latest *Annual Benchmarking Report: Electricity distribution network service providers* in November 2024 (2024 *Annual Benchmarking Report*). Energex received a copy of the preliminary results in August 2024.

We have reviewed our revealed base year opex against the expected outcomes of the preliminary economic benchmarking models and analysis applied in recent determinations. As a result of our assessment, when using the 2023-24 actual costs as incurred, Energex is expected to receive an 11.5 per cent efficiency adjustment to the base year. Further detail on how our base year opex compares to economic benchmarks is included in the *Frontier Economics - Estimates of efficient base year opex for Energex and Ergon Energy* (Attachment 6.03).

We have reviewed our revealed costs for 2023-24 and have excluded non-recurrent costs. During the 2023-24 base year, there were significant weather events, including the major Gold Coast storm event in December 2023. We have removed $23.6 million ($2023-24) in emergency response costs based on the difference between our actual costs and a historical five-year average. We have also excluded the movement in provisions from our base year costs, in line with previous AER determinations.

Following the adjustments, we have included a 4.2 per cent efficiency adjustment to our base year costs in the SCS opex model. The above adjustments are illustrated in Figure 11.

Figure 11: 2023-24 base year efficiency adjustments



6.4.2 Step changes

The *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.[54] In our Regulatory Proposal, Energex identified and quantified one significant cost for the 2025-30 regulatory control period which was treated as a step change.

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

In the Draft Decision, the AER rejected the proposed $14.6 million for the smart meter data step change and substituted a forecast of $3.4 million based on Option 1.[55]

The AER and EMCa provided feedback which included:

- in our face-face workshop, EMCa questioned the unit rate for live data acquisition, thinking it was too low and did not reflect the likely costs associated with the initiative. We have looked at the costs of our current data acquisition and revised the unit rate estimates up in line with this feedback

[54] AER, *Better Resets Handbook – Towards consumer centric network proposals*, December 2021, p. 28.
[55] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 6 – Operating expenditure*, September 2024, p.40, 42.

- our key assumptions around the safety benefits of live data and 6-hourly data were higher than they had expected. We have analysed our current live data trials and utilised these findings to revise down our expectation on resolving safety and reliability issues on our network in line with this data, and
- since our Regulatory Proposal, the AEMC has released its draft decision on *Accelerating smart meter data deployment*.[56] This has clarified that only 24-hour data is available free of charge and that there will be Business-to-Business (B2B) costs payable by a Network Service Provider to acquire more granular data. We had originally thought that the data would be 6-hourly, and no B2B costs would be incurred. This has been incorporated into our cost-benefit analysis modelling. The AER also released guidance on the carbon emissions price,[57] which we have utilised in our revised modelling in valuing the benefits of smart meter data as it relates to the integration of distributed energy resources.

In our Revised Regulatory Proposal, we have forecast a step change of $15.7 million. Our preferred option (Option 2) includes:

- acquiring advanced (near real-time) power quality data for 25 per cent of the available smart meters for our overhead service lines and 10 per cent for our underground service lines, 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 distributed energy resources and export at the most efficient level. This would provide 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 in accordance with the AEMC's recommendation, and
- provision of a data platform and B2B system to land and analyse the smart meter data that we acquire. This cost will be shared across Energex and Ergon Energy Network and has been assigned proportionally according to the number of smart meter points we expect in each network.

Table 21 summarises the costs we are forecasting for the 2025-30 regulatory control period associated with acquiring smart meter data. There were no smart meter data costs included in the 2023-24 base year.

Table 21: Forecast step changes for 2025-30 period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Smart meter data business case	3.35	2.55	2.91	3.26	3.59	**15.7**

Note 1: Total may not add due to rounding.

We have resubmitted our revised Smart Meter Data Acquisition Business Case for the AER's consideration (refer to Attachment 6.04).

56 AEMC, *Accelerating Smart Meter Deployment, Draft rule determination*, 4 April 2024.

57 AER, *AER guidance and explanatory statement - Valuing emissions reduction*, May 2024, p. 4.

6.4.3 Rate of change

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

6.4.3.1 Price growth

Our price trend adjustments in this Revised Regulatory Proposal are based on the average of the updated forecasts prepared by Oxford Economics (Attachment 6.02), and the forecast commissioned by the AER (Deloitte Access Economics) used in its Draft Decision.[58] The forecast price growth rates are provided in Table 22.

Table 22: Forecast real price growth 2025-30

Per cent	2025-26	2026-27	2027-28	2028-29	2029-30
Real labour forecast – Oxford Economics	0.64%	1.05%	1.05%	1.28%	1.38%
Real labour forecast – Deloitte Access Economics	0.61%	0.79%	0.77%	0.88%	1.09%
Average of real labour forecasts	0.63%	0.92%	0.91%	1.08%	1.23%
Superannuation guarantee	0.50%	0.00%	0.00%	0.00%	0.00%
Average plus superannuation guarantee	1.13%	0.92%	0.91%	1.08%	1.23%
Price growth (assuming 59.20% labour)	0.67%	0.55%	0.54%	0.64%	0.73%

6.4.3.2 Output growth

We have updated the output growth forecasts in our Revised Regulatory Proposal to reflect actual 2023-24 data and the latest available forecasts. We have applied the output change measures and respective weightings in the preliminary *Quantonomics Report*[59] expected to be released with the AER's 2024 *Annual Benchmarking Report*. Our forecast output growth rates are outlined in Table 23.

Table 23: Forecast output growth 2025-30

	Average weighting	2025-26	2026-27	2027-28	2028-29	2029-30
Customer numbers	39.2%	1,658,594	1,678,004	1,697,474	1,716,888	1,736,169
Circuit length	19.9%	57,670	58,133	58,589	59,063	59,573
Ratcheted maximum demand	41.0%	5,880	5,928	5,970	6,024	6,065
Average output growth		1.13%	0.95%	0.90%	0.97%	0.89%

[58] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 6 – Operating expenditure*, September 2024, p. 36.

[59] The AER provided the Quantonomics Report to all DNSPs as part of its standard feedback process for its Annual Benchmarking Report.

6.4.3.3 Productivity growth

Given the affordability concerns raised by our customers, our Executive Management and Board decided to apply a 1.0 per cent annual productivity rate to the forecast opex in our Regulatory Proposal. This exceeded the AER's standard rate of 0.5 per cent. Energex is maintaining its commitment and will apply a productivity rate of 1.0 per cent in the Revised Regulatory Proposal.

Productivity improvements can result from technical change, efficiency, or economies of scale. The reductions in opex due to both the applied efficiency adjustment and productivity factor 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 while recognising customers' affordability concerns. Further detail on how Energex is proposing to achieve the productivity improvements is included in Attachment 6.05.

6.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Energex SCS Opex Model	6.01	Energex - 6.01 - Model - SCS Opex model - November 2024 - public
Input cost escalation forecasts to 2029/30	6.02	Energex - 6.02 - Oxford Economics Australia – Input Cost Escalation Forecasts to 2029/30 - November 2024 - public
Frontier Economics – Estimates of efficient base year opex	6.03	Energex - 6.03 - Frontier Economics - Estimates of efficient base year opex for Energex and Ergon Energy - October 2024 - public
Smart Meter Data Acquisition Business Case	6.04	Energex - 6.04A - Business Case - Smart Meter Data Acquisition - November 2024 - public Energex - 6.04A - Business Case - Smart Meter Data Acquisition - November 2024 - confidential Energex - 6.04B - NPV Model - Smart Meter Data Acquisition - November 2024 - confidential
Productivity Initiatives	6.05	Energex - 6.05 - Productivity Initiatives - November 2024 - confidential

7.
Incentive Schemes

Key messages:

- Energex supports the application of incentive schemes to DNSPs.
- We continue to support the application of the STPIS, CESS, DMIS and DMIAM to Energex in the 2025-30 regulatory control period. However, we now propose that the EBSS should be suspended in this period.
- We accept the AER's Draft Decision that the customer service (telephone answering) component of the STPIS should remain. Customers have indicated that they can "live with" this decision given the CSIS will not apply to Energex in 2025-30.
- In the absence of the CSIS, we remain committed to publishing a Customer Service Performance Measures Scorecard independently of the regulatory determination process to provide greater transparency of our performance against the measures most valued by our customers.

7.1 Overview of the AER's Draft Decision

We consider that the application of incentive schemes is in the long-term interests of our customers. These schemes incentivise networks like Energex 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.

Table 24 summarises what we proposed and the AER's Draft Decision on incentive schemes for the 2025-30 regulatory control period.

Table 24: Summary of the AER's Draft Decision on incentive schemes

Scheme	Regulatory Proposal	Draft Decision
CESS	Apply for 2025-30. CESS penalties of $48.3 million.	Accepted application for 2025-30. Recalculated CESS penalties to $72.8 million due to revenue adjustments.
EBSS	Apply for 2025-30. EBSS negative carryovers of $121.8 million.	Accepted application for 2025-30. Recalculated EBSS negative carryovers to $119.7 million based on updated inputs.
STPIS	Apply for 2025-30. The customer service component of the STPIS (telephone answering) should not apply and the overall revenue at risk cap should be reduced to ±1.8 per cent of annual forecast revenue due to telephone answering not applying. Performance targets and incentive rates updated for 2025-30.	Accepted application for 2025-30. Included telephone answering component of STPIS and consequently set revenue at risk at ±2.0 per cent of annual forecast revenue. Performance targets and incentive rates to be recalculated with updated inputs for Final Decision.
DMIS	Apply for 2025-30.	Accepted application for 2025-30.
DMIAM	Apply for 2025-30. Allowance of $7.5 million.	Accepted application for 2025-30. Allowance to be set in Final Decision.

Scheme	Regulatory Proposal	Draft Decision
CSIS	Not apply for 2025-30.	Accepted.
ESIS	Not apply for 2025-30.	Accepted.

7.2 Our response to the AER's Draft Decision

We have modified our position on which incentive schemes will apply to us for the 2025-30 regulatory control period. Our revised position is to not apply the EBSS for the 2025-30 regulatory control period for the reasons set out in section 7.4.

Table 25 summarises our response to the key issues raised by the AER in its Draft Decision regarding the application of the incentive schemes.

Table 25: How we have responded to AER's Draft Decision on incentive schemes

Issue in Draft Decision	Our response	More information
CESS	We have updated the CESS revenue adjustment calculations.	Section 7.3.
EBSS	We have changed our position and propose that the EBSS should be suspended.	Section 7.4.
STPIS	We have updated the calculations of our STPIS targets and incentive rates. We have accepted the AER's Draft Decision to apply the customer service component (telephone answering) of the STPIS.	Section 7.5.
DMIS and DMIAM	We have updated the DMIAM allowance calculations.	Section 7.6.

7.3 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.

7.3.1 Revenue impact in the 2025-30 period

In the Regulatory Proposal we estimated total CESS penalties of $48.3 million, consisting of:

- $64.3 million revenue decrements for spending more than the efficient capex forecast set by the AER for the 2020-25 regulatory control period, and
- $16.0 million revenue increment for the true-up for the CESS payment calculated in the previous determination for the 2019-20 year.

The AER's Draft Decision estimated total CESS penalties of $72.8 million. The increase in CESS penalties in the AER's Draft Decision was due to the true-up calculation where the AER used updated 2019-20 actual capex. This resulted in a revenue decrement of $6.2 million instead of our proposed $16.0 million revenue increment (a net change of $22.2 million dollars). In addition, the AER also updated the other inputs, including the consumer price index (CPI) and the rate of return (WACC) to reflect up-to-date information. [60]

[60] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 9 – Capital expenditure sharing scheme*, September 2024, p. 4-5.

Our response to the AER's Draft Decision on total CESS penalties is summarised in Table 26. We have updated the revenue decrements for spending above the AER's allowances for the 2020-25 regulatory control period to reflect our actual capex for the 2023-24 year and updated forecast for the 2024-25 year. We accept the AER's true-up adjustment for the 2019-20 year. This results in total revised CESS penalties of $113.4 million.

Table 26: Summary of our response to AER's Draft Decision on total CESS penalties

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
CESS penalties	-64.3	-66.6	-2.3	Accept	-107.2	-42.9
CESS true-up for 2019-20	16.0	-6.2	-22.2	Accept	-6.2	-22.2
Total[1]	**-48.3**	**-72.8**	**24.5**	**Accept**	**-113.4**	**-65.1**

Note 1: Totals may not add due to rounding.

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

In the Regulatory Proposal, and consistent with the F&A, we proposed the continued application of the CESS in the 2025-30 regulatory control period. The AER's Draft Decision proposed that the CESS would continue to apply.[61] We accept the AER's Draft Decision.

7.4 Efficiency Benefit Sharing Scheme

The EBSS is intended to provide a continuous incentive for DNSPs to pursue efficiency improvements in opex and to share these with customers. The EBSS is intrinsically linked to the revealed cost base-step-trend approach, where forecast opex is based on a network business's recent actual opex from a single year (the base year). The opex is forecast by trending forward the base year opex, accounting for changes in key inputs costs, outputs and productivity. Other efficient costs not captured in the base year are added as step changes in the forecast.

The EBSS is intended to address two potential incentive problems associated with the revealed cost forecasting approach:

- the incentive to increase opex in the base year so as to increase the forecast opex, and
- the incentive to defer efficiency improvement until after the base year so as to avoid a lower opex forecast.

The combination of the EBSS and the revealed cost forecasting approach means the network business earns the same reward and penalty in each year of the regulatory control period for efficiency gains or losses. At a 6 per cent real WACC, and with network businesses holding efficiency gains or losses for six years, this results in network businesses sharing opex efficiency gains and losses approximately 30:70 with customers. It is important to reiterate that the EBSS only works as intended where the opex forecast is based on the network business's actual revealed cost. Departing from the business's actual costs, for example by substituting benchmarking opex for actual costs, distorts how the EBSS works and can potentially result in a business being penalised more than 100 per cent of the efficiency losses. It is for this reason that the EBSS should only apply where the AER uses actual revealed costs to forecast opex.

[61] Ibid, p. 2.

In our Regulatory Proposal, we proposed that the EBSS should apply in the 2025-30 regulatory control period and included $121.8 million in negative EBSS carryovers (i.e. penalties) from the current 2020-25 regulatory control period. These negative carryovers were based on our forecast base year opex (i.e. 2023-24). While we did apply an efficiency adjustment to the base year and thereby did not rely on our actual costs, we considered that the adjustment was not material enough to distort how the EBSS works and thus proposed that the EBSS should continue to apply and included the negative carryovers. The AER's Draft Decision was to include $119.7 million in negative EBSS carryovers, based on the most recent inflation data.[62] In our Regulatory Proposal we also proposed that, based on our forecast 2023-24 base year, the EBSS should apply in the 2025-30 regulatory control period.

Our response to the AER's Draft Decision on EBSS penalties is summarised in Table 27.

Table 27: Summary of our response to AER's Draft Decision on EBSS penalties

$m, real 2024-25	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
EBSS penalties	-121.8	-119.7	-2%	Modify	0.0	121.8

The position for our Revised Regulatory Proposal has changed from that proposed in our Regulatory Proposal. We now propose that:

- the penalties from the application of the EBSS in the current 2020-25 regulatory control period should not be applied in the 2025-30 regulatory control period, and
- the EBSS should be suspended for the 2025-30 regulatory control period.

The reason for the change in our position is that our actual opex for 2023-24 (the base year) has significantly exceeded the forecast that we provided in the Regulatory Proposal and used for the AER's Draft Decision. We previously advised the AER of this likely outcome, and this was noted in the Draft Decision.

As a result of the increase in the base year, our analysis indicates that the benchmark efficiency adjustment for Energex (excluding movement in provisions) has increased to approximately 8.4 per cent.[63] This efficiency adjustment includes uncontrollable (and one-off) storm costs, which we have adjusted for in revising our opex forecasts. However, under the EBSS, these costs are not an approved exclusion. This means that, while they are excluded from the base year (in forecasting opex), we are penalised under the EBSS, distorting the sharing of the efficiency losses.

We consider that the magnitude of the efficiency adjustment means we are no longer relying on our revealed costs to forecast our opex. Instead, we are primarily relying on benchmarking. The opex we have proposed in Chapter 6 is $2,510.2 million. If our revealed costs were used to forecast opex, the forecast is estimated to be $2,700.1 million, $189.9 million higher than the benchmark estimate.

As mentioned previously, the EBSS is intended to work in conjunction with a revealed cost forecasting approach. When used together it allows for the fair sharing of efficiency gains and losses. As revealed costs (in 2023-24) have not been applied in forecasting our opex (see

[62] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 8 – Efficiency benefit sharing scheme*, September 2024, p. 1.

[63] We have removed non-recurrent storm costs from our base year, to apply an adjustment of 4.2 per cent in the SCS opex model.

Chapter 6), we consider it is not appropriate to apply the associated penalties to our revenues for the 2025-30 regulatory control period. This is because:

- if the penalties were included for 2025-30 (which have been recalculated at $331.8 million based on our actual 2023-24 opex), in addition to an efficiency adjustment in the base year, Energex would carry a greater share of losses than initially intended when the EBSS was applied for the 2020-25 regulatory control period
- it is not consistent with the intended operation of the EBSS and the objective of fairly sharing efficient losses as defined under the NER, and
- this position is consistent with previous AER determinations, namely the 2024-29 Draft Determination for Evoenergy.[64]

In addition, as it is uncertain whether revealed costs for the 2025-30 regulatory control period will be relied on in forecasting future (2030-35) opex, our position is that the EBSS should also not be applied in the 2025-30 regulatory control period. Energex already has an incentive to make efficiency improvements in the 2025-30 regulatory control period given our actual opex has been subject to an efficiency adjustment.

7.5 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.

In our Regulatory Proposal, we supported the Final F&A position to continue to apply version 2.0 of the STPIS in the 2025-30 regulatory control period. We also proposed that the customer service component of the STPIS (telephone answering) should not apply and, with the proposed removal of the customer service component of the STPIS, that the overall revenue at risk cap be reduced to ±1.8 per cent from the current ±2.0 per cent. This is because a ±0.2 per cent revenue at risk cap currently applies to the customer service component.

The AER's Draft Decision did not accept the removal of the customer service (telephone answering) component of the STPIS due to the absence of a CSIS and the importance of phone communications in emergency events.[65]

Our VOC Panel recommended the removal of the customer service (telephone answering) component of the STPIS because panel members considered that we should not be incentivised for good customer service. In light of this position, we explored the AER's Draft Decision on STPIS with our VOC Panel in October 2024. The views of the panel were that they could "live with" the continuation of the customer service (telephone answering) component of the STPIS because the AER accepted that a CSIS would not apply to Energex and because we remain committed to publishing a Customer Service Performance Measures Scorecard.

While we are disappointed that the AER did not place a greater weight on the views of our VOC Panel, we can accept the inclusion of the customer service (telephone answering) component of the STPIS.

Table 28 sets out how we have responded to the Draft Decision on key STPIS elements.

[64] AER, *Draft Decision, Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 8 – Efficiency benefit sharing scheme*, September 2024, pp. 4-5.
[65] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 10 – Service target performance incentive scheme*, September 2024, pp. 6-9.

Table 28: How we have responded to AER's Draft Decision on STPIS elements

Matter	Regulatory Proposal	Draft Decision	Our Response
Revenue at risk	±1.8 per cent.	±2 per cent.	Accept.
Segmenting of network	Central Business District (CBD), urban and short rural.	Accepted.	Accept.
Applicable parameters for the s-factor	Reliability of supply: system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI).	Not accepted as also applying customer service (telephone answering) parameter.	Accept.
Performance targets	Based on the average performance over the past five regulatory years.	Accepted.	Accept.
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.	Accepted.	Accept.
Incentive rates	Applied the 2019 value of customer reliability (VCR) adjusted to June 2024 CPI values to set incentive rates for SAIDI and SAIFI.	Accepted.	Accept.
Guaranteed service level component	Not applied (a jurisdictional guaranteed service level scheme applies).	Accepted.	Accept.

7.5.1 Proposed performance targets and incentive rates

We have updated our STPIS reliability performance targets and incentive rates to take into account our actual performance for 2023-24 and updated inputs used in calculating incentive rates. We note that the revised incentive rates are a placeholder and will be updated in the AER's Final Decision to incorporate updated forecast inputs, including the AER's revised VCR study due to be published in December 2024. The updated targets and incentive rates are provided in Table 29 and Attachment 7.04.

Table 29: Updated proposed STPIS targets and incentive rates

Proposed targets	Performance target	Incentive rate
Unplanned SAIDI		
CBD	3.5082	0.00249
Urban	55.7875	0.05262
Short rural	131.7357	0.02083
Unplanned SAIFI		
CBD	0.0427	0.13623
Urban	0.5519	3.54655
Short rural	1.1488	1.59255
Customer Service		
Telephone answering		-0.04000

7.6 Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism

We accept the AER's Draft Decision to apply the DMIS and DMIAM to us for the 2025-30 regulatory control period.[66] 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.

We have updated our proposed DMIAM allowance to $7.5 million based on the outputs of our revised PTRM. We accept that the final amount of the DMIAM allowance will be based on the final PTRM.

7.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
SCS CESS Model	7.01	Energex - 7.01 - SCS CESS Model - November 2024 - public
SCS CESS True-Up Model	7.02	Energex - 7.02 - CESS True-Up Model - November 2024 - public
SCS EBSS Model	7.03	Energex - 7.03 - EBSS Model - November 2024 - public
STPIS Targets and Incentive Rates Model	7.04	Energex - 7.04 - STPIS Targets and Incentive Rates - November 2024 - public

[66] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Chapter 11 - Demand management incentive scheme and Demand management innovation allowance mechanism*, September 2024, pp. 1-2.

8.
Annual Revenue Requirement

Key messages:

- We have revised our proposed revenue for the 2025-30 regulatory control period to account for revisions to other elements of our proposal.
- Our revised proposed revenue of $8,140.8 million (real $2024-25, unsmoothed) is in line with our initial Regulatory Proposal and 2.1 per cent above the AER's Draft Decision.

8.1 Overview of the AER's Draft Decision

The revenue requirement is the total revenue for the 2025-30 regulatory control period that we require to enable us to continue to build and maintain a safe and reliable network.

In our Regulatory Proposal, we proposed an annual revenue requirement of $8,151.5 million (real $2024-25, unsmoothed), which was 18 per cent above our current period revenue. The increase in revenue was driven by uncontrollable factors such as rising interest rates and inflation as well as increasing capex and opex requirements for our business.

The AER's Draft Decision reduced our proposed revenue by $178.3 million or 2.2 per cent to $7,973.2 million. The revenue reductions were mainly due to the AER's Draft Decision to reduce our proposed forecast capex for the 2025-30 regulatory control period, updated revenue adjustments and the true-up for the CESS. The AER also made several updates to other key inputs such as the rate of return and expected inflation which had minor impacts on revenue.[67]

8.2 Our response to the AER's Draft Decision

We have revised our proposed forecast revenue for the 2025-30 regulatory control period to $8,140.8 million (real $2024-25, unsmoothed) as set out in Table 30. This is $167.6 million more than the AER's Draft Decision revenue and $10.7 million less than our Regulatory Proposal.

Table 30: Our revised proposed revenue for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Return on capital	897.3	901.0	908.6	918.5	928.4	4,553.8
Regulatory depreciation	177.6	198.5	223.2	238.9	243.2	1,081.4
Opex	505.8	503.2	501.4	500.4	499.4	2,510.2
Revenue adjustments	-21.2	-21.2	-21.2	-21.2	-21.1	-105.9
Tax allowance	13.7	16.1	20.0	26.0	25.5	101.3
Annual revenue requirement (unsmoothed)	1,573.1	1,597.6	1,632.0	1,662.7	1,675.4	8,140.8
Annual expected revenue (smoothed)	1,517.8	1,562.5	1,609.7	1,709.2	1,751.9	8,151.1
X factors	-6.32%	-2.95%	-3.02%	-6.18%	-2.50%	

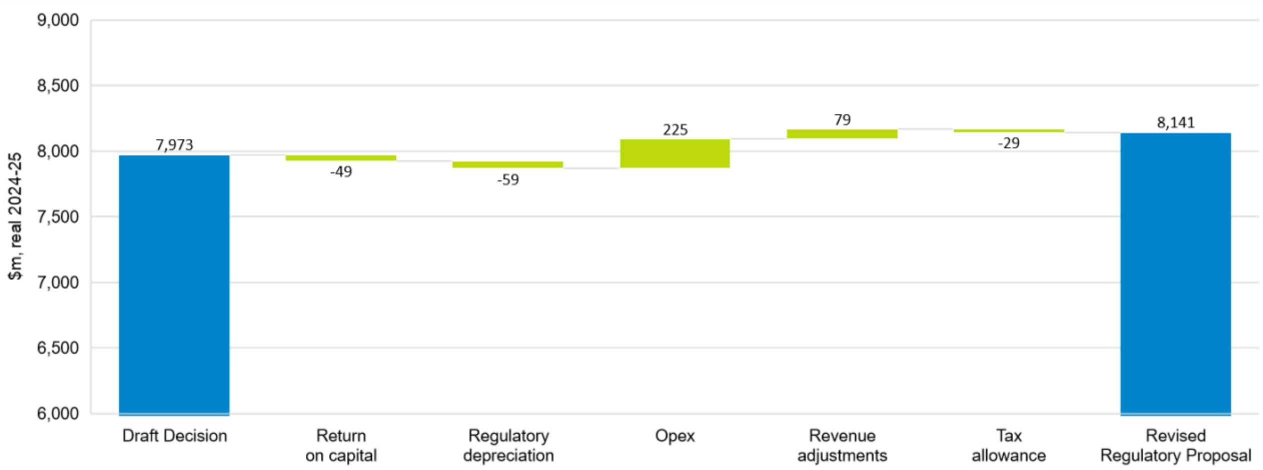
[67] AER, *Draft Decision, Energex Electricity Distribution Determination 2025-2030, Attachment 1 – Annual revenue requirement*, September 2024, p 6.

The increase in our revised revenue above the AER's Draft Decision is mainly due to:

- our updated opex increasing above what we proposed in our Regulatory Proposal and accepted by the AER in the Draft Decision
- our proposal to suspend the application of the EBSS and not apply the penalties for the 2020-25 regulatory control period
- our revised forecast capex being above the AER's Draft Decision, and
- other mechanistic updates we have made to the calculation of our opening RAB to reflect actual expenditure over the 2023-24 year and updated forecast capex for the final year of the current regulatory control period.

Figure 12 sets out the key differences between our Revised Regulatory Proposal building blocks revenue proposal and the AER's Draft Decision.

Figure 12: Changes in revised revenue from the Draft Decision



We note that the revenue will likely change again in the AER's Final Decision due to the use of placeholder values for key inputs such as the rate of return and expected inflation in our Regulatory Proposal, the AER's Draft Decision and our Revised Regulatory Proposal.

The following sections provide further details on our response to the AER's Draft Decision.

8.3 Rate of return

Our Revised Regulatory Proposal applies a placeholder rate of return (or WACC) of 5.97 per cent (nominal vanilla) as set out in Table 31. The rate of return is estimated by applying the 2022 *Rate of Return Instrument*. The AER's Draft Decision updated our initial placeholder rate of return and used the prevailing rates at the end of July 2024 for both the return on equity and return on debt.[68] Our Revised Regulatory Proposal uses the prevailing rates at the end of September 2024 for the return on equity. However, for the return on debt, we adopted the approach from our Regulatory Proposal of using the prevailing rates from the previous annual return on debt update.

[68] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 3 – Rate of return*, September 2024, pp. 1-2.

Table 31: Revised Rate of Return for the 2025-30 regulatory control period

Parameter	Revised Regulatory Proposal
Nominal risk-free rate	3.96%
Market risk premium	6.20%
Equity beta	0.6
Return on equity	7.68%
Return on debt (average)	4.83%
Nominal vanilla WACC (average)	5.97%

The rate of return will be updated in the Final Decision to reflect our nominated averaging periods for the return on equity and return on debt, which the AER approved in the Draft Decision.[69] Consistent with the 2022 *Rate of Return Instrument*, the AER's Final Decision on return on equity will be fixed for the 2025-30 regulatory control period while the return on debt will be updated annually.

8.4 Regulatory asset base

8.4.1 Opening RAB as at 1 July 2025

We propose a revised opening RAB value of $15,695.8 million ($, nominal) as at 1 July 2025 as set out in Table 32. Our revised opening RAB is $126.3 million higher than the AER's Draft Decision.

Table 32: Revised RAB for the 2020-25 regulatory control period

$m, nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Opening RAB	12,874.5	12,916.3	13,322.9	14,342.3	14,984.3
Net Capex	380.1	392.9	447.5	588.5	766.9
Straight-line Depreciation	-449.1	-438.1	-471.5	-527.6	-567.8
Indexation	110.8	451.8	1,043.4	581.1	449.5
Interim closing RAB	12,916.3	13,322.9	14,342.3	14,984.3	15,633.0
Adjustment for previous regulatory control period					18.1
Final year adjustment					44.7
Closing RAB as at 30 June 2025					15,695.8

[69] Ibid, p. 2.

The Draft Decision accepted our proposed approach to calculating the opening RAB as at 1 July 2025, including our proposals to:

- self-fund the overspend in ICT over the capex ex post period (2018-23), and
- capitalise lease costs in accordance with the accounting standard (AASB 16) and add our existing lease costs to the RAB with a remaining asset life of 4.3 years.[70]

In addition, the Draft Decision made several mechanistic updates to the calculation of the opening RAB, including updating for actual CPI for 2023-24, forecast CPI for 2024-25 and the 2024-25 annual rate of return update. The AER also made other minor amendments that we agreed to, including:

- updating actual gross capex and asset disposal inputs for 2019-23 to be consistent with the Annual Reporting RINs for these years, and
- updating the asset disposals for 2023-25 for the “Motor Vehicles” asset class to reflect the estimated gross proceeds from sale.[71]

We accept the Draft Decision. However, we have updated the calculation of the opening RAB in the roll forward model (RFM) to reflect:

- actual 2023-24 capex values - our Regulatory Proposal and the Draft Decision used forecast values for 2023-24, and
- updated 2024-25 capex forecasts - we have updated the forecast we included in our initial proposal to reflect our latest data.

8.4.2 Forecast RAB

We propose a revised forecast closing RAB of $17,978.5 million ($, nominal) by 30 June 2030 as set out in Table 33. This is $559.2 million higher than the AER’s Draft Decision.

Table 33: Revised RAB for the 2025-30 regulatory control period

$m, nominal	2025-26	2026-27	2027-28	2028-29	2029-30
Opening RAB	15,695.8	16,160.4	16,636.6	17,069.5	17,508.4
Net Capex	647.2	686.1	675.7	706.3	750.0
Straight-line Depreciation	-629.9	-670.5	-717.0	-753.8	-778.8
Indexation	447.3	460.5	474.1	486.4	498.9
Closing RAB	16,160.4	16,636.6	17,069.5	17,508.4	17,978.5

The revised forecast RAB reflects the updates we have made in the PTRM, including the updated opening RAB, our revised forecast capex for the 2025-30 regulatory control period (as explained in Chapter 5) and updated rate of return.

[70] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 2 – Regulatory asset base*, September 2024, p. 13.
[71] Ibid, p. 13.

8.5 Regulatory depreciation

We propose revised forecast regulatory depreciation of $1,081.4 million (real $2024-25) for the 2025-30 regulatory control period as set out in Table 34. Our revised regulatory depreciation is $59.1 million lower than the AER's Draft Decision.

Table 34: Revised regulatory depreciation for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Straight-line depreciation	612.4	633.8	659.0	673.6	676.8	**3,255.7**
Less indexation	-434.8	-435.3	-435.8	-434.7	-433.6	**-2,174.3**
Regulatory depreciation	177.6	198.5	223.2	238.9	243.2	**1,081.4**

Note 1: Totals may not add due to rounding.

The AER's Draft Decision accepted our proposed approach to calculating regulatory depreciation, including:

- the use of the straight-line depreciation method
- the continued use of the "year-by-year tracking" approach for implementing straight-line depreciation of existing assets and forecast capex
- the continued use of existing asset classes and standard asset lives, and
- two new asset classes of "Initial leases" and "Lease extensions" for the capitalisation of lease expenditures, with standard asset lives of 10 years and five years respectively.[72]

We accept the AER's Draft Decision. However, we have updated the calculation of regulatory depreciation to reflect:

- the updated opening RAB as at 1 July 2025
- our revised forecast capex, and
- updated rate of return.

We have also used the AER's Draft Decision forecast for expected inflation of 2.85 per cent to calculate the indexation component of regulatory depreciation.[73]

8.6 Opex

We propose revised opex of $2,510.2 million (real $2024-25) as set out in Chapter 6. This is $225.3 million higher than the Draft Decision.[74]

8.7 Corporate income tax

We propose revised tax allowances of $101.3 million (real $2024-25) as set out in Table 35. This is $29.0 million lower than the Draft Decision.

[72] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 4 – Regulatory depreciation*, September 2024, pp. 1-2.
[73] Ibid, p. 8.
[74] AER, *Draft Decision, Energex Distribution Determination 2025 to 2030, Overview*, September 2024, pp. 15-16.

Table 35: Revised corporate income tax for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Tax payable	31.9	37.4	46.6	60.5	59.3	**235.7**
Less value of imputation credits	-18.2	-21.4	-26.6	-34.5	-33.8	**-134.4**
Corporate income tax	13.7	16.1	20.0	26.0	25.5	**101.3**

Note 1: Totals may not add due to rounding.

The Draft Decision accepted our proposed approach to calculating corporate income tax, including:

- the calculation of the opening tax asset base (TAB) as at 1 July 2025 in the RFM
- the income tax rate of 30 per cent and value of imputation credits (gamma) of 0.57 as set out in the 2022 *Rate of Return Instrument*
- the approach for immediate expensing of capitalised overheads
- exempting forecast capex for buildings and in-house software for the 2025-30 regulatory control period from the diminishing value tax depreciation method and continuing to apply straight-line tax depreciation for these assets
- the use of the year-by-year depreciation tracking method
- proposed standard tax asset lives, except for “in-house software” which was amended in the Draft Decision to be consistent with the *Income Tax Assessment Act* 1997, and
- two new asset classes of “Initial leases” and “Lease extensions” for the capitalisation of lease expenditures, with standard asset lives of 10 years and five years respectively.[75]

We accept the AER’s Draft Decision. However, we updated the calculation of corporate income tax to reflect an updated opening TAB, revised forecast capex and revised forecast of immediately expensed capex.

8.8 Revenue adjustments

We propose a negative revised revenue adjustment of $105.9 million (real $2024-25) as set out in Table 36. This is $79.4 million lower than the Draft Decision.

Table 36: Revised revenue adjustments for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
CESS	-22.7	-22.7	-22.7	-22.7	-22.7	**-113.4**
EBSS	0.0	0.0	0.0	0.0	0.0	**0.0**
DMIAM	1.5	1.5	1.5	1.5	1.5	**7.5**
Revenue adjustments[1]	**-21.2**	**-21.2**	**-21.2**	**-21.2**	**-21.2**	**-105.9**

Note 1. Totals may not add due to rounding.

[75] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 7 – Corporate income tax*, September 2024, p. 2.

The changes in our revised revenue adjustments are due to:

- updated CESS penalties to reflect actual 2023-24 capex and an updated forecast 2024-25 capex, and
- our proposal to suspend the EBSS and not apply penalties for the 2020-25 regulatory control period (as explained in Chapter 7).

8.9 Smoothed revenue and X factors

We propose revised smoothed revenue of $8,151.1 million and the X factors set out in Table 37.

Table 37: Smoothed revenue and X factors for the 2025-30 regulatory control period

$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Annual revenue requirement (unsmoothed)	1,573.1	1,597.6	1,632.0	1,662.7	1,675.4	**8,140.8**
Annual expected revenue (smoothed)	1,517.8	1,562.5	1,609.7	1,709.2	1,751.9	**8,151.1**
X factors	-6.32%	-2.95%	-3.02%	-6.18%	-2.50%	

Note 1: Totals may not add due to rounding.

Annual revenue requirements can vary significantly from year-to-year. Revenue smoothing is applied to minimise price volatility. As suggested by the AER in its Draft Decision, our Revised Proposal smoothing profile accounts for the Queensland Government's Solar Bonus Scheme expiring on 1 July 2028. This is consistent with the approach applied by the AER in its Draft Decision for SA Power Networks. [76]

Further, the NER stipulate that the smoothing must be set so as to minimise, as far as reasonably possible, the difference between the annual revenue requirement (unsmoothed) and the expected revenue (smoothed) for the final year of the regulatory control period. The AER's Draft Decision noted that a divergence of up to 3 per cent is reasonable.[77] However, we also note that in the SA Power Networks' Draft Decision, the AER considered it reasonable to relax the threshold to 5 per cent to minimise the first-year price impacts.[78] We have applied the 5 per cent threshold in developing our revised smoothing profile. The divergence between our smoothed and unsmoothed revenue is 4.9 per cent.

8.10 Revised 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 $33 or 4.6 per cent annually for residential customers, $100 or 4.6 per cent annually for small business customers, and $1,804 or 5.3 per cent annually for a large business connected on the low voltage network.[79] The revised indicative bill impacts are outlined in Table 38.

[76] AER, *Draft Decision, Energex Electricity Distribution Determination 2025-2030, Attachment 1 – Annual revenue requirement*, September 2024, p. 8.

[77] Ibid, p. 8.

[78] AER, *Draft Decision, SA Power Networks Electricity Distribution Determination 2025 to 2030, Attachment 1 – Annual revenue requirement*, September 2024, p. 9.

[79] 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 2.85 per cent based on the AER's methodology set out in the PTRM.

Table 38: Revised indicative bill impacts

$, nominal	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Average Annual change
Residential[1]							
Indicative annual bill	$660	$696	$735	$767	$803	$827	
Annual ($) change		$36	$39	$32	$36	$24	$33
Annual (%) change		5.4%	5.6%	4.3%	4.7%	3.0%	4.6%
Small business[2]							
Indicative annual bill	$1,980	$2,172	$2,294	$2,357	$2,452	$2,481	
Annual ($) change		$192	$121	$64	$94	$29	$100
Annual (%) change		9.7%	5.6%	2.8%	4.0%	1.2%	4.6%
Large low voltage business[3]							
Indicative annual bill	$30,788	$32,418	$34,99	$36,701	$37,714	$39,808	
Annual ($) change		$1,630	$2,577	$1,706	$1,013	$2,093	$1,804
Annual (%) change		5.3%	7.9%	4.9%	2.8%	5.6%	5.3%

Notes:
1. Residential typical customer: calculated as a weighted average of the bill impact on the residential flat and transitional demand tariffs at the total network level assuming annual energy usage of 5,024kWh and monthly demand of 3.48kW.
2. Small business customer: customer on the default transitional demand tariff with annual consumption of 19,692kWh and a monthly peak demand of 7.02kW.
3. Large low voltage business typical customer: customer on default low voltage TOU demand tariff with annual consumption of 319,878kWh and with a monthly peak demand of 90.51kVA.

8.11 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
SCS AER RFM Model	8.01	Energex - 8.01 - Model SCS AER RFM - November 2024 - public
SCS AER Depreciation Model	8.02	Energex - 8.02 - Model SCS AER Depreciation - November 2024 - public
SCS AER PTRM Model	8.03	Energex - 8.03 - Model SCS AER PTRM - November 2024 - public

9.
Network Tariffs and Pricing

Key messages:

- The AER's Draft Decision did not approve our initial 2025-30 TSS.
- We have reflected most elements of the AER's Draft Decision in our revised TSS, including changing the default tariff for residential and small business customers from a TOU demand to a TOU energy tariff and introducing a new optional TOU energy tariff for large low voltage business customers.
- The AER's Draft Decision has also resulted in Energex modifying our position on transitioning customers to two-way tariffs and storage tariffs.
- Our revised TSS includes additional information required by the AER in order to make it capable of acceptance.

9.1 Overview of the AER's Draft Decision

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 Energex's costs. We recover our costs classified as SCS through our network tariffs. 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.

In January 2024, we submitted our proposed network tariff structures and assignment arrangements to the AER in our 2025-30 TSS and TSES. Both documents provided information about our network tariffs and compliance with the NER, with the TSES providing additional information on the drivers of change and how our customers' preferences and input were incorporated into our proposal.

The AER's Draft Decision was to not approve our proposed 2025-30 TSS. The AER was not satisfied that all elements of the proposed TSS comply with the pricing principles and other applicable requirements of the NER and does not contribute to achievement of the National Electricity Objective. Elements of our proposed 2025-30 TSS which were not approved by the AER are as follows:

- tariff assignment for residential and small business customers
- proposed two-way tariffs
- tariff assignment for large low voltage business customers
- proposed flexible load control tariffs, and
- grid-scale storage tariffs.[80]

The AER was satisfied that many elements of our proposed 2025-30 TSS comply with the pricing principles and accepted the following in its Draft Decision:

- tariff structures for residential and small business customers, not including two-way tariffs or the proposed new optional flexible load control tariffs

[80] AER, *Draft Decision, Ergon Energy and Energex Electricity Distribution Determination 2025-2030, Attachment 19 – Tariff structure statement,* September 2024, p. 4-5.

- tariff structures for large low voltage and high voltage business customers, not including two-way tariffs
- tariff assignment for high voltage business customers
- continuation of existing primary and secondary load control tariffs
- tariff streamlining and withdrawal of obsolete or closed tariffs, and
- our approach to setting and assigning customers to ICC tariffs.[81]

We are not proposing any changes to these aspects of our initial proposal in our revised TSS.

9.2 Our response to the AER's Draft Decision

Our revised TSES (Attachment TSS-02) provides information on how we have responded to the AER's feedback and our revised 2025-30 TSS (Attachment TSS-01) demonstrates how our proposed network tariffs for the 2025-30 regulatory control period comply with the requirements of the NER and the AER's *Export Tariff Guidelines*.

Our revised TSS includes amendments reflecting the AER's Draft Decision in order for the TSS to be approved. Exceptions relate to AER decisions that were not consistent with our own customer feedback or operational implementation capability. In these instances, we have made alternative changes in response to the AER's decision. Examples include assignment arrangements for residential and small business customers, two-way tariffs and dynamic storage tariffs.

We have also responded to the AER's request for additional information to be included in documentation, including in the areas of customer bill impact, dynamic connections, flexible load tariffs and tariff streamlining.

Table 39 sets out the elements of our TSS which were not approved by the AER, how we have responded to the AER's feedback and where to find more information.

Table 39: How we have responded to AER's Draft Decision on network tariffs

Issue in Draft Decision	Change requested by the AER	Our response
Tariff assignment for residential and small business customers	Change default assignment for residential and small business customers with smart meters from the TOU demand and energy tariffs to the TOU energy tariffs. Reassign existing customers from current default transitional demand tariffs to TOU energy tariffs.	Assignment arrangements are amended in our revised TSS in response to the AER's Draft Decision. New and upgrading residential and small business customers will be assigned to TOU energy tariffs. Retailer-led meter upgrades will result in an assignment to TOU energy tariffs 12 months after the financial year in which the upgrade occurred. The TOU demand and energy tariffs will remain as optional tariffs. TOU energy tariffs will not be assigned retrospectively to customers on the current default tariff. These customers will remain on their current default tariff but retain the option to access TOU energy tariffs during the 2025-30 period if they choose.

[81] Ibid, p. 4.

Issue in Draft Decision	Change requested by the AER	Our response
Contingent tariff adjustments	Include further information on contingent tariff adjustments to remove obsolete tariffs within the 2025-30 period.	In response to the AER's Draft Decision and customer feedback we will remove the contingent tariff adjustment from our revised TSS. Instead, we will withdraw the legacy small business Wide Inclining Fixed tariff from 1 July 2025. We expect this change will increase transparency for basic meter customers and ultimately assist with the transition to a more cost-reflective tariff.
Two-way tariffs	Include an explicit export tariff transition strategy. Convert export charges and basic export level from kW to kWh. Include network bill impact analysis for small businesses and large customers to face two-way tariffs.	Our Initial TSS introduced two-way tariffs, commencing for new customers from 1 July 2026 and transitioning to all customers from 1 July 2028. In response to customer feedback, customers opting into a dynamic connection would be able to opt-out of two-way tariffs. The AER rejected our tariff structures for two-way tariffs and requested additional changes and more information be provided in the revised TSS in order for it to be capable of acceptance. Our revised TSS does not make these changes but instead extends the introduction of two-way tariffs to beyond the 2025-30 regulatory control period.
Tariff assignment for SAC Large business customers	Offer TOU energy tariffs for SAC Large customers with demand greater than 120 KVA and consumption less than 160 MWh per annum.	In response to the AER's Draft Decision we have introduced a new optional TOU energy tariff for SAC Large customers with demand greater than 120 KVA and consumption less than 160 MWh per annum from 1 July 2025.
Flexible load control tariffs	Include further description of control arrangements that are contained in the QECM, including the relationship between the QECM and TSS, and the extent to which control arrangements influence tariff options, including the new flexible load tariffs.	Our revised TSS includes further information on the new residential and small business flexible load tariffs. Additional information regarding the QECM is also included.
Grid-scale storage tariffs	Provide further detail on grid-scale storage tariffs, including more detail on the critical peak pricing mechanism.	Our initial TSS proposal was to include two grid-scale storage tariff structure options: the dynamic price storage tariff and dynamic flex storage tariff. The dynamic flex storage tariff (with no critical peak prices) will be offered as an optional tariff from 1 July 2025. We consider this simplified tariff structure proposal compliant with the NER and capable of understanding by customers and retailers.

Issue in Draft Decision	Change requested by the AER	Our response
		The dynamic price storage tariff incorporating critical peak period import and export charge components will be offered as a trial tariff from 1 July 2025. In addition, a complementary secondary tariff incorporating critical peak period import and export reward components will be trialled from 1 July 2025. The secondary tariff will be made available to customers on both the dynamic flex and dynamic price storage tariffs.

9.3 Other changes since our initial TSS

9.3.1 Delayed introduction of two-way tariffs

Our initial TSS introduced two-way tariffs, commencing for new customers from 1 July 2026 and transitioning to all customers from 1 July 2028.

However, since submitting our initial TSS and publication of the AER's Draft Decision, Energex has decided to propose a delay in the introduction of two-way tariffs to the next regulatory control period. In our view, the benefits of introducing export pricing at this stage are likely to be limited and outweighed by the costs associated with its implementation. Further analysis suggests that it is unlikely that the quantum of export charges will be sufficient to result in any meaningful change in customer behaviour and it is uncertain whether they would be incorporated into retail offers. Therefore, the transaction costs associated with implementing export prices for both networks and retailers are unlikely to be offset by export tariff uptake. Consequently, Energex will focus on a demand-side solution through TOU pricing to encourage a shift in customer behaviour, before implementing two-way tariffs in the future.

Our two-way pricing transition strategy was built on cautious support for two-way tariffs, with concerns that more time was needed to adjust to this change. Customers were of the view that the transition to two-way pricing should not occur until other reforms have been embedded first and is supported by increased education for customers.

There are also considerable uncertainties in the build-up of policy reform in line with a greater penetration of smart meters. Smart meter customers have only recently started to see more cost-reflective tariffs and price signals. Customers have expressed frustration in the way some retailers have passed through network tariffs and retailers have highlighted the significant challenges in explaining these changes to end-use customers.

Delaying the introduction of two-way pricing will allow other policy frameworks to be embedded and provide more time for Energex to deliver better information to customers on how the two-way tariffs would work and how such a tariff would impact them if introduced.

9.4 Ongoing customer engagement

We commenced our tariff engagement in 2021, to develop the initial approaches towards refining network tariffs, customer impact framework and customer education. Since submission of our initial TSS, we have continued to engage with residential and business customers and other stakeholders on our tariffs and indicative prices.

We engaged with our VOC Panel to discuss indicative prices for residential customers in the context of affordability. The Panel had mixed views on the pace of change around tariff reform, particularly with respect to the introduction of two-way pricing and noted the need for further customer education. The export tariff transition strategy set out in our TSS therefore outlines our decision to suspend implementation of two-way tariffs until the next regulatory control period.

In recognition of the value and contribution that the NPWG brought to the development and review of our network tariff strategy, we took the opportunity to transition the NPWG to a representative forum that would assist us in the finalisation of our 2025-30 TSS. An open expression of interest process resulted in an expansion of the NPWG membership with broadened representation. Membership now covers both Queensland networks, with representation from large and small businesses, the retail sector and representatives from different cohorts of residential customers.

The NPWG met five times between February and October 2024. The NPWG's focus has been on providing input and consensus positions on issues raised either through the AER's Issues Paper, stakeholder responses, or the Draft Decision. The NPWG explored the following network tariff-related topics and issues in depth:

- load control tariffs and the QECM
- dynamic connections and two-way tariffs
- storage tariffs and the level of fixed charges
- TOU energy tariffs for customers consuming 100-160MWh per annum, and
- demand tariffs and their appropriateness as the default tariffs for residential customers.

The NPWG's feedback on these issues is provided in our TSES.

We also continued to engage with large customers primarily through individual one-on-one discussions. These discussions were intended to enable large customers to explore their specific issues of concern and indicative network prices. Our large customers continue to tell us that the cost of electricity is a key consideration in their business investment decision-making.

9.5 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
2025-30 Indicative Network Prices	9.01	Energex - 9.01 - 2025-30 Indicative Network Prices - November 2024 - public
Model – Endgame Economics - LRMC	9.02	Energex - 9.02 - Endgame Economics - LRMC model - November 2024 - public
Model – Stand alone and Avoidable	9.03	Energex - 9.03 - Stand alone and avoidable model - November 2024 - public

10. Metering


WARNING
SHORT CIRCUIT CURRENT
OPEN CIRCUIT VOLTAGE
GARAGE
ENERGEX

Key messages:

- The AER's Draft Decision accepted most of our metering services proposal, including the reclassification of legacy metering services as SCS and the application of a revenue cap.
- The AER provided a substitute forecast for metering opex due to updated inputs, which resulted in a substitute annual revenue requirement.
- Due to the uncertainty of legacy metering replacement volumes, the AER's Draft Decision also provided for a true-up mechanism for opex.
- We accept the AER's Draft Decision with respect to metering.

10.1 Overview of the AER's Draft Decision

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. The Power of Choice reforms fundamentally changed our role in the provision of metering services, reducing it to managing and maintaining our remaining Type 6 basic accumulation meters ("legacy meters") as they are progressively phased out and replaced by Type 4 smart (digital) meters.

What we proposed and the AER's Draft Decision on metering is summarised in Table 40.

Table 40: Summary of the AER's Draft Decision on metering[82]

Category	Regulatory Proposal	Draft Decision
Service classification	Reclassify legacy metering services from ACS to SCS and application of a revenue cap form of control	Accepted
Acceleration of depreciation	Accelerate the recovery of legacy meter depreciation to achieve full recovery by the end of the 2025-30 regulatory control period	Accepted
Metering revenue components	No new capex, standard revenue components applied such as return on existing capital, depreciation, opex and tax allowance	Reduced opex resulting in a lower revenue
Metering charges	Recover costs through a flat per customer charge to low voltage customers, regardless of customer, tariff, or meter type	Accepted
True-up mechanism for opex	N/A	Introduction of a true-up mechanism for opex to account for uncertainty of legacy metering replacement volumes

[82] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 20 – Metering services*, September 2024, pp. 6-7, 15.

10.2 Our response to the AER's Draft Decision

We accept the AER's Draft Decision for metering, including the addition of a true-up mechanism for opex. As requested by the AER, we have provided an amended bottom-up opex model with our Revised Regulatory Proposal to allow for the outworking of the true-up mechanism (refer to Attachment 10.01).

Based on the latest information available, inputs have been updated consistent with other aspects of our Revised Regulatory Proposal. Our metering revenue forecast is now $376.0 million for the 2025-30 regulatory control period. This is 0.3 per cent lower than the AER's Draft Decision. Our response to the AER's Draft Decision on our forecast metering revenue, and our updated revenue building blocks, is summarised in Table 41. The annual metering services charges to be recovered from all low voltage customers over the 2025-30 regulatory control period is shown in Table 42.

Table 41: Summary of our response to AER's Draft Decision on metering revenue

$m, nominal	Regulatory Proposal	Draft Decision	Difference to Regulatory Proposal	Summary of our response	Revised Regulatory Proposal	Difference to Regulatory Proposal
Return on capital	40.3	39.9	-0.4	Modify[1]	38.8	-1.5
Regulatory depreciation	210.7	209.9	-0.8	Accept	209.9	-0.8
Opex	138.3	125.6	-12.7	Accept	125.6	-12.7
Tax allowance	0.0	0.0	0.0	Accept	0.0	0.0
Annual revenue requirement (unsmoothed)	389.3	375.4	-13.9	Modify	374.3	-15.0
Smoothed revenue	394.4	377.2	-17.2	Modify	376.0	-18.4
X factors[2]	-8.2%	-22.3%		Modify	-21.9%	

Note 1: Modify classification as revisions made to calculation inputs.
Note 2: Negative X factor implies an increase in revenue.

Table 42: Forecast metering services annual charges

$m, nominal	2025-26	2026-27	2027-28	2028-29	2029-30
Annual Metering Charge ($/year)	44.03	44.75	45.49	46.25	47.04

10.3 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Model – Metering Opex 2025-30	10.01	Energex - 10.01 - Metering Opex Model 2025-30 - November 2024 - public
Model – Metering RFM 2025-30	10.02	Energex - 10.02 - Metering RFM 2025-30 - November 2024 – public
Model – Metering PTRM 2025-30	10.03	Energex - 10.03 - Metering PTRM 2025-30 - November 2024 - public
Model – Metering Pricing Model 2025-30	10.04	Energex - 10.04 - Metering Pricing Model 2025-30 - November 2024 - public

11.
Alternative Control Services

Key messages:

- The AER found that the proposals for ACS were largely reasonable and only made minor substitutions for some pricing inputs.
- The AER accepted our proposal to reclassify legacy metering services from ACS to SCS but did not accept our proposal to reclassify supply abolishment services from ACS to SCS.
- We largely accept the AER's Draft Decision, except for the decisions relating to quoted services labour rates and reclassification of supply abolishment services.

11.1 Overview of the AER's Draft Decision

ACS are distribution services that are customer-specific or customer-requested services and are paid for by the customer who seeks the service. 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).

What we proposed and the AER's Draft Decision on ACS is summarised in Table 43.

Table 43: Summary of the AER's Draft Decision on ACS

ACS Category	Regulatory Proposal	Draft Decision
Public lighting	A Public Lighting Strategy, which included: • achieve 100 per cent deployment of LED public lights • fund the upfront capital cost of the conversion of Rate 1 and Rate 2 conventional assets to LED • extend the cost recovery timeframe out to 2035 for the residual value of the remaining conventional lights • introduce a user-pays approach for smart control devices, and • forecast proposed public lighting expenditure, revenue and pricing for 2025-30.	Accepted strategy and made minor amendments to expenditure, revenue and pricing.

ACS Category	Regulatory Proposal	Draft Decision
Ancillary Services	For fee-based ancillary services: • changes to service dimensions, such as travel time, time to complete a job and number of crew required • rationalise our suite of services by discontinuing the service permutations which have had little to no uptake over the past three years, and • draft prices. For quoted ancillary services: • labour rates specific to the quoted service to improve cost-recovery, and • apply a margin to promote competitive neutrality.	For fee-based ancillary services: • maintained price cap form of control with labour price escalation as X factor • accepted all changes to service offerings and assumptions • accepted all labour category rates excluding the administrative category, and • accepted all service prices with revised escalation excluding property search fees. For quoted ancillary services: • applied the lower of maximum efficient benchmarked labour rates or proposed labour rates.
Security Lighting	Cease to provide and install new security lights for new customers but continue to maintain and operate security lights for existing customers until they transition to alternative solutions.	Accepted pricing approach for security lighting.
Reclassification of Legacy Metering Services	Reclassify legacy metering services from ACS to SCS to reduce the disproportionate cost burden on customers who will be the last to receive a smart meter, including vulnerable customers.	Accepted the reclassification from ACS to SCS.
Reclassification of Supply Abolishment Services	Reclassify the removal of connection assets (or "supply abolishment") from ACS to SCS due to public safety concerns.	Not accepted as work is driven by a single customer, not a shared network service and other DNSPs have it classified as ACS.

11.2 Our response to the AER's Draft Decision

We largely accept the AER's Draft Decision, with proposed exceptions set out in the sections below.

11.3 Public lighting

The public lighting services provided by Energex include the provision, maintenance, and operation of public lighting assets. In developing our Regulatory Proposal, we collaborated extensively with our customers. Following this broad consultation process and with customer endorsement, we proposed to convert all conventional lights to LED technology by 2030. The strategy included the initiative to recover the residual value of the remaining conventional lights out to 2035, both to support the full deployment of LEDs during this transition period as well as to mitigate customer impact. We are pleased that the AER supports our proposed roll-out of LED public lighting and proposed public lighting strategy.

In our submission we also indicated to customers that we would pursue a public lighting engagement plan which pivots from a Regulatory Proposal development project activity to a business-as-usual implementation phase post 1 July 2025. As foreshadowed, in October 2024 we held an engagement session that focused on informing customers about:

- the outcomes of the AER's Draft Decision
- the proposed process and participation in a pilot of the upcoming Smart Lighting System, and
- the outcomes of the AEMC's Final Determination on *Unlocking CER Benefits through flexible trading* rule change.[83]

Energex is committed to continual engagement with our customers, stakeholders, and their representatives to enable the successful deployment of our endorsed public lighting strategy.

While the AER's Draft Decision considered our public lighting proposal to be reasonable, it amended labour escalators, WACC and inflation to be consistent with draft decisions on other relevant aspects of our Regulatory Proposal.[84]

We updated the modelling for our Revised Regulatory Proposal by applying the most recent WACC and labour rates, and by updating actuals for 2023-24. In doing this update, we identified that the modelling submitted in the Regulatory Proposal and used in the AER's Draft Decision had not been updated to incorporate 2022-23 actual capex and was instead based on forecast capex for the year. Actual 2022-23 capex significantly exceeded the forecast capex for the year due to the acceleration of the conversion of mercury vapour lights to LEDs. The high level of actual spend continued into 2023-24. This higher than forecast spend has increased the projected opening Public Lighting Asset Base and consequently impacted forward prices. However, this increase was offset by applying the revised WACC and labour rates, which had a downward impact on forecast public lighting revenue. The outcome of these modelling updates and corrections is that the average price impact for customers is an initial estimated increase of 15 per cent for the 2025-26 year followed by an average annual 3 per cent decrease for the remaining four years of the 2025-30 regulatory control period.[85]

Our response to the AER's Draft Decision is summarised in Table 44. Attachment 11.03 provides our updated opex, capex and revenue for public lighting and Attachment 11.06 provides the revised prices.

Table 44: How we have responded to AER's Draft Decision on public lighting

Issue in Draft Decision	Our response	More information
The AER amended labour escalators to be consistent with the SCS opex draft decision.	For the Revised Regulatory Proposal, Energex has applied labour escalators consistent with those used in the calculation of SCS opex.	Attachment 11.01
The AER updated the WACC used to determine public lighting charges to be consistent with its Draft Decision on rate of return.	Energex has applied the same WACC value to determine public lighting charges for the Revised Regulatory Proposal as is used to derive SCS revenue.	Attachment 11.03

83 AEMC, *Unlocking CER benefits through flexible trading, Rule determination*, 15 August 2024, available on the AEMC's website.
84 AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, p. 23.
85 The average customer impact reflects the impact of the replacement of all the Rate 1 and Rate 2 conventional lights to LED, and the reassignment of the Rate 4 assets to Rate 2 LED tariffs.

Issue in Draft Decision	Our response	More information
The AER has substituted inflation inputs with placeholder values that will be updated in the Final Decision.	Energex has applied the AER's estimate of inflation from the Draft Decision to calculate public lighting charges for the Revised Regulatory Proposal. We note that this is a placeholder value that will be updated by the AER for the Final Decision.	Attachment 11.03
The AER is open to Energex introducing pricing for new public lighting services, provided it conforms to the control mechanism for quoted services.[86]	Energex is not proposing to introduce any new services in this Revised Regulatory Proposal. Energex will treat any new services implemented at the request of a customer during the next regulatory control period as a quoted service.	N/A

11.4 Ancillary services

Ancillary services are non-routine services provided to individual customers as requested, for example, temporary disconnections and reconnections, supply abolishment and meter testing. 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.

Our Regulatory Proposal included 165 individual ancillary network services that are either fee-based or quoted services provided to individual customers. These services are subject to an AER price cap. Fee-based services are homogeneous services provided on request for the benefit of a single customer, rather than a service supplied to customers collectively. The price for fee-based services is determined using a cost build up approach based on the labour rates, vehicle costs, and overheads that are anticipated to apply in the delivery of the services over the 2025-30 regulatory control period. Quoted services are services that vary in nature, and the scope of the work is specific to the individual customer's requirements. The price for quoted services will reflect the approved rates at the time the work is requested.

For the 2025-30 regulatory control period, we proposed rates for six labour categories for fee-based services and nine labour categories for quoted services, reflecting the different types of labour resources required for the provision of ancillary network services. We also proposed the following changes to fee-based services compared to the current period:

- **Service consolidation** – discontinuation of 28 services which had limited uptake in the prior three years
- **Health and safety requirements** – increase to crew size from one to two crew members for high-risk services
- **Updated contractor rates –** extended current procurement contracts with higher rates due to shortage of reputable and qualified service providers, and
- **Updated travel time** – increased average travel time from 31 to 31.5 minutes due to increased traffic congestion within South East Queensland.

The AER's Draft Decision did not accept our proposal as submitted. The AER adjusted the proposed 2025-26 prices with Draft Decision price caps that reflect its Draft Decision on CPI and X factors.[87]

[86] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 16 – Alternative control services*, September 2024, pp. 23-24.
[87] Ibid, p. 6.

As a result of benchmarking, the AER did not accept the following labour rates and instead replaced them with an alternative efficient labour rate:

- Administrative (business and after hours)
- Quoted Services Administrative (business and after hours)
- Quoted Services Professional and Managerial (business hours)
- Quoted Services Supervisor (business hours), and
- Quoted Services System Operator (business hours).[88]

The AER did accept the proposed changes to service inputs for travel time, contractor costs and crew size for high-risk services.[89]

We accept the AER's Draft Decision on fee-based ancillary network services in full. However, although the majority of our proposed quoted services labour rates were accepted on the basis that they were below the AER's benchmark maximum labour rate, we have revised all quoted service labour category rates. The updated labour category rates reflect 2023-24 costings resulting from changes to wages and employment conditions under our Enterprise Bargaining Agreement and other general employment conditions, which were not reflected in the original proposed base rates. This has increased the average quoted service base labour rates by 15 per cent relative to the Draft Decision. Our full price list for ancillary network services is provided in Attachment 11.07.

Table 45 outlines our response to the AER's Draft Decision on ancillary network services.

Table 45: How we have responded to AER's Draft Decision on ancillary network services

Issue in Draft Decision	Our response	More information
Price caps for fee-based services	Accept prices and X factors as set out in the AER's Draft Decision Ancillary Services Model.	Attachment 11.07
Labour rates for quoted services	Updated rates to reflect 2023-24 costing.	Attachment 11.07

11.5 Security lighting

Security lighting services generally involve installation, operation, maintenance and replacement of lighting equipment which is typically mounted to our distribution network poles and structures.

Our Regulatory Proposal reconfirmed our view, as stated in our submission to the AER's F&A process, that new security lighting installations will no longer be offered from 1 July 2025. We also proposed to set prices for 2025-26 by escalating current prices using the CPI-X approach consistent with the price cap form of control.

The AER considered the proposed changes and pricing approach to security lighting services to be reasonable.[90]

We accept the AER's Draft Decision on security lighting services in full. The proposed security lighting tariffs for the 2025-30 regulatory control period are provided in Attachment 11.06.

88 Ibid, p. 11.
89 Ibid, pp. 11-12.
90 Ibid, p. 14.

11.6 Service reclassification for supply abolishment services

The AER's Draft Decision did not accept a request by Energex to reclassify the removal of connection assets (or "supply abolishment") from ACS to SCS. This decision was based on the following reasons:

- supply abolishments are driven by a single customer, and
- other DNSPs offer the service as an ACS.[91]

However, Energex remains of the view that there is a case to change the service classification for simple supply abolishments to SCS, primarily for public safety reasons and to align with similar classification decisions that apply to distributors in Victoria and Tasmania.[92]

This matter is discussed in Chapter 12, section 12.3.1.

11.7 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File name
Public Lighting Capex and Opex Forecasting Model	11.01	Energex - 11.01 - Public Lighting Capex and Opex Forecasting Model - November 2024 - public
Public Lighting RFM	11.02	Energex - 11.02 - Public Lighting RFM - November 2024 - public
Public Lighting PTRM	11.03	Energex - 11.03 - Public Lighting PTRM - November 2024 – public
Public Lighting PTRM to Pricing Intermediary Model	11.04	Energex - 11.04 - Public Lighting PTRM to Pricing Intermediary Model - November 2024 - public
Public Lighting Pricing Model 2025-30	11.05	Energex - 11.05 - Public Lighting Pricing Model 2025-30 - November 2024 - public
ACS Price Schedule 2025-30	11.06	Energex - 11.06 - ACS Price Schedule 2025-30 – public
ACS Ancillary Services Model 2025-30	11.07	Energex - 11.07 - ACS Ancillary Services Model 2025-30 - November 2024 - public

[91] Ibid. pp. 13-14.

[92] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, and AER, *Framework and approach: TasNetworks distribution and transmission (Tasmania), Regulatory control period commencing 1 July 2024*, July 2022.

12.
Other Regulatory Matters

Key messages:

- Energex accepts the AER's Draft Decision on control mechanisms, negotiating framework, nominated pass through events, contingent projects and connection policy.
- We largely accept the AER's Draft Decision on classification of services, with the exception of the decision to not accept the proposed reclassification of supply abolishment services from SCS to ACS.
- We consider that an amendment to the F&A to mitigate the significant community safety risks associated with failure to abolish supply, and to align with other jurisdictions' classifications, warrants further consideration by the AER.
- We have addressed the requirements of the AER's *Confidentiality Guideline* as to the matters for which we are claiming confidentiality.

12.1 Overview of the AER's Draft Decision

Energex's Regulatory Proposal set out our proposed approach to a number of regulatory matters, including classification of services, control mechanisms, negotiating framework, nominated pass through events, contingent projects and connection policy. The AER's Draft Decision on these key matters is summarised in Table 46.

Table 46: Summary of AER's Draft Decision on Key Regulatory Matters

Matter	Regulatory Proposal	Draft Decision
Classification of services	Energex broadly supported the AER's proposed service classifications as set out in the Final F&A. However, we proposed that legacy metering services should be reclassified as SCS. We also subsequently proposed that supply abolishment services should be reclassified from ACS to SCS.	The AER's Draft Decision is to maintain the service classifications set out in the Final F&A, except for legacy metering services which will be reclassified as SCS, and the inclusion of data services as a common distribution service. The AER did not accept our proposal to reclassify supply abolishment services from ACS to SCS.
Control mechanisms	Energex accepted the AER's control mechanism decision as set out in the Final F&A, namely: • revenue cap for SCS, and • price cap for ACS. We proposed a departure from the control formulae for SCS provided in the Final F&A.	The AER's Draft Decision for Energex on the form of control mechanism for SCS is a revenue cap, which now includes legacy metering services. The AER adopted the revised SCS control formulae and separate metering-specific parameter definitions to separate legacy metering revenue from the main SCS. The form of control mechanism for ACS is a price cap. The Draft Decision includes the price cap formulae for fee-based ancillary services, public lighting services and quoted ancillary network services.
Negotiating framework	Energex's proposed negotiating framework for the 2025-30 regulatory control period was submitted with the Regulatory Proposal for approval.	The AER's Draft Decision is that the proposed negotiating framework submitted by Energex will apply for the 2025-30 regulatory control period.

Matter	Regulatory Proposal	Draft Decision
Pass through events	Energex nominated the following additional pass through events: • insurance coverage event • insurer's credit risk event • terrorism event, and • natural disaster event.	The AER's Draft Decision is to accept Energex's nominated pass through events (insurer's credit risk, natural disaster, terrorism and insurance coverage) consistent with the Regulatory Proposal, subject to minor amendments to the proposed definition for the insurance coverage event.
Contingent projects	Energex did not propose any contingent projects.	As Energex did not propose any contingent projects for the 2025-30 regulatory control period, the AER did not make a decision under clause 6.12.1(4A) of the NER.
Connection policy	Energex's proposed connection policy for the 2025-30 regulatory control period was submitted with the Regulatory Proposal for approval.	The AER's Draft Decision is to approve the connection policy proposed by Energex.

12.2 Our response to the AER's Draft Decision

Energex appreciates the AER's consideration of the matters raised in our Regulatory Proposal and largely accepts the AER's Draft Decision in this Revised Regulatory Proposal. Our response to the AER's Draft Decision is discussed further below.

12.3 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 AER's Draft Decision proposes to maintain the service classifications set out in the Final F&A, with the following exceptions:

- reclassifying legacy metering services from ACS to SCS, and
- including data services as a common distribution service.[93]

However, the AER did not accept Energex's proposal to reclassify supply abolishment services from ACS to SCS.[94]

Energex's Revised Regulatory Proposal accepts the AER's Draft Decision, with the exception of the determination that supply abolishment services should remain classified as ACS, for reasons outlined below.

12.3.1 Classification of supply abolishment services

The AER's Draft Decision did not accept a request by Energex to reclassify the removal of connection assets (or "supply abolishment") from ACS to SCS. This decision was based on the following reasons:

- supply abolishments are driven by a single customer, and
- other DNSPs offer the service as an ACS.[95]

[93] AER, *Draft Decision Energex Electricity Distribution Determination 2025 to 2030, Attachment 13 – Classification of Services*, September 2024, p. 1.
[94] Ibid. p. 5.
[95] Ibid, pp. 5 and 9.

However, Energex remains of the view that there is a case to change the service classification for simple supply abolishments to SCS, primarily for public safety reasons and to align with similar classification decisions that apply to distributors in Victoria and Tasmania.[96]

Energex accepts that, in principle, a supply abolishment is driven by a specific customer and the costs can be attributed to the customer to whom the service is provided. This reasoning is consistent with the current F&A for the 2020-25 regulatory control period which classifies this service as ACS under the connection application and management service group. However, notwithstanding the current ACS classification, Energex has identified that, in practice, there has been an increase in the number of instances where customers attempt to circumvent the fee by closing their electricity account and vacating the premises without requesting a supply abolishment. In a growing number of these instances, failure to carry out supply abolishment works is resulting in safety risks at building demolition, removal or relocation sites and urgent action is required by Energex to make the premises safe.

To provide further clarity, Energex's proposal is to reclassify simple supply abolishment (i.e. for small customer connections) as a standard control common distribution service. This reclassification would remove any disincentive to initiate a supply abolishment due to reluctance to incur an ACS fee and thus prevent consequent safety hazards. We propose, however, that more complex supply abolishment (i.e. for large customer connections) should remain classified as ACS under the connection application and management service group (i.e. the current "removal or repositioning of connection assets" service). Refer to Attachment 12.01.

We acknowledge that this proposed change in classification would result in supply abolishment-related costs for small customer connections being recovered from all customers through network charges rather than from an individual customer. However, we consider this activity is consistent with other activities concerned with providing a safe and reliable electricity supply to customers and that the benefits of mitigating public safety risks outweighs a "user-pays" approach.

Further, Energex's proposal is consistent with the classification decisions that have been applied to distributors in Victoria and Tasmania for similar supply abolishment services. For example, the AER's Final F&A for TasNetworks for the 2024-29 regulatory control period provided the following reasoning for accepting the request for a classification change from ACS to SCS for supply abolishment of a basic connection:

> "We accept TasNetworks submission regarding the public safety risks associated with energised service conductors in abandoned buildings. When we classified a similar supply abolishment service for Victorian distributors, we recognised that on leaving premises the departing party may have a strong incentive to avoid paying the full costs of abolishment. Although the service applies to individual customers, and warrants an alternative control classification, we nevertheless recognise the significant public safety hazard and accept TasNetworks' request."[97]

Accordingly, Energex considers that an amendment to the F&A to mitigate the significant community safety risks associated with failure to abolish supply, and to align with other jurisdictions' classifications, warrants further consideration by the AER.

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[96] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, and AER, *Framework and approach: TasNetworks distribution and transmission (Tasmania), Regulatory control period commencing 1 July 2024*, July 2022.

[97] AER, *Final framework and approach for TasNetworks for the regulatory control period commencing 1 July 2024*, July 2022, p. 28.

12.4 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.[98] The NER also specify that the form and formulae of the control mechanisms must be set out in the F&A.[99]

The AER's Draft Decision is that the form of control mechanism for SCS is a revenue cap and the control mechanism for ACS is a price cap as set out in the Final F&A.[100]

The AER's Draft Decision and Energex's responses are set out below.

12.4.1 Standard control services

Energex's Revised Regulatory Proposal accepts the AER's Draft Decision for SCS, including the following:

- the control mechanism formulae and formula parameter definitions for SCS, including:
    - the metering-specific definitions for legacy metering services (which have been reclassified from ACS to SCS), and
    - definitions for the I, B, C and X factors
- the metering services true-up mechanism
- deliberately under-recovered revenue
- unpaid network charges resulting from retailer of last resort events
- side constraint mechanism
- reporting on designated pricing proposal charges, and
- reporting on jurisdictional scheme amounts and rounding inputs in the annual pricing proposal process.

12.4.2 Alternative control services

Energex's Revised Regulatory Proposal accepts the AER's Draft Decision in relation to ACS as follows:

- the control mechanism formulae and formula parameter definitions for ACS, including the new margin and tax factor definitions
- provision for the addition of new ACS during the 2025-30 regulatory control period, and
- requirements relating to transparency of billing for quoted services.

12.5 Negotiating framework

Although none of Energex's services will be classified as negotiated distribution services in the 2025-30 regulatory control period, we are required to submit a negotiating framework to the AER for approval.[101]

[98] Clause 6.2.5(a) of the NER.
[99] Clauses 6.12.3(c) and 6.12.3(c1) of the NER.
[100] AER, *Energex and Ergon Energy Electricity Distribution Determination 2025-2030*, *Attachment 14 – Control Mechanisms Draft Decision* - September 2024, p. 1.
[101] Clause 6.8.2(c)(5) of the NER.

The AER's Draft Decision is to accept Energex's proposed negotiating framework submitted with our Regulatory Proposal.[102]

Energex accepts the AER's Draft Decision.

12.6 Pass through events

The cost pass through mechanism allows Energex 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.

The NER allow all DNSPs to apply for a cost pass through for prescribed events (i.e. regulatory change, service standard, tax change and retailer insolvency) and to nominate additional pass through events in its Regulatory Proposal.[103]

Energex proposed four nominated pass through events for the 2025-30 regulatory control period as follows:

- insurance coverage event
- insurer's credit risk event
- terrorism event, and
- natural disaster event.

The AER's Draft Decision is to accept Energex's nominated pass through events consistent with the Regulatory Proposal, subject to minor amendments to the definition proposed for the insurance coverage event.[104]

Energex accepts the AER's Draft Decision on the nominated pass through events and event definitions for the 2025-30 regulatory control period.

12.7 Contingent projects

Energex did not propose any contingent projects for the 2025-30 regulatory control period. Therefore, the AER did not make a decision under clause 6.12.1(4A) of the NER.[105]

12.8 Connection policy

The NER require DNSPs to prepare a connection policy setting out the circumstances in which a retail customer or real estate developer may be required to pay a connection charge for the provision of a connection service under Chapter 5A.[106]

Energex submitted our connection policy for the 2025-30 regulatory control period with the Regulatory Proposal.

[102] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030, Attachment 17 – Negotiated services framework and criteria*, September 2024, p. 1.
[103] Clauses 6.6.1(a1) and 6.6.1(a1)(5) of the NER.
[104] AER, *Draft Decision, Energex Electricity Distribution Determination 2025 to 2030*, *Attachment 15 – Pass through events*, September 2024, p. 1.
[105] AER, *Draft Decision, Energex Electricity Distribution Determination 2025-2030, Overview*, September 2024, p. 32.
[106] Clause 6.7A.1 of the NER.

The AER's Draft Decision was to approve Energex's proposed connection policy for the 2025-30 regulatory control period.[107]

Energex accepts the AER's Draft Decision.

12.9 Confidential information

Our confidentiality template (Attachment 12.02) sets out the information provided as part of this Revised Regulatory Proposal for which Energex is claiming confidentiality.

12.10 Supporting documentation

The following documents support this chapter:

Document Name	Reference	File Name
Classification of services	12.01	Energex - 12.01 - Classification of services - November 2024 – public
Confidentiality template	12.02	Energex - 12.02 - Confidentiality template - November 2024 - public

[107] AER, *Draft Decision, Energex Electricity Distribution Determination 2025-2030, Attachment 18 – Connection policy*, September 2024, p. 2.

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
ACS	Alternative control service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Brisbane 2032	Brisbane 2032 Olympic and Paralympic Games
CAC	Connection asset customer
CAM	Cost allocation methodology
Capex	Capital expenditure
CBD	Central business district
CESS	Capital Expenditure Sharing Scheme
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
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
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
F&A	Framework and Approach
GWh	Gigawatt hours
ICC	Individually calculated customer
ICT	Information and communications technology
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light emitting diode

Chapter 13: Glossary

Term	Meaning
LRMC	Long run marginal cost
MW	Megawatts
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
Regulatory Proposal	Energex's Regulatory Proposal for the next regulatory control period submitted under clause 6.8 of the NER
RFM	Roll forward model
RIN	Regulatory Information Notice
RRG	Reset Reference Group
SAC	Standard asset customer
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCS	Standard control service
STPIS	Service Target Performance Incentive Scheme
TAB	Tax asset base
TOU	Time of use
V	Volt
VCR	Value of customer reliability
WACC	Weighted average cost of capital

Part of Energy Queensland

Project team: RDP2025Connect@energyq.com.au

energex.com.au

Energex Limited
GPO Box 1461
Brisbane QLD 4001

2-23-0333