Issues Paper

Ergon Energy and Energex electricity distribution determinations 2025–30

March 2024

AUSTRALIAN ENERGY REGULATOR

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1 Introduction

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia. We regulate electricity networks in all jurisdictions except Western Australia. The regulatory framework governing electricity transmission and distribution networks is the National Electricity Law and Rules (NEL and NER). Our work in this sector is guided by the National Electricity Objective (NEO).

Regulated network businesses must periodically apply to us to determine the maximum allowed revenue they can recover from consumers for using their networks. On 31 January 2024 we received revenue proposals from Queensland electricity distribution network service providers Ergon Energy Networks (Ergon) and Energex, for the period 1 July 2025 to 30 June 2030 (2025–30 period).

In assessing these proposals our goal is to ensure customers are better off both now and in the future. We do this by balancing the need for prudent and efficient investment to maintain the networks and prepare them to support the energy transition, while at the same time ensuring consumers facing cost-of-living pressures pay no more than necessary for electricity services that meets their current and future needs.

In this Issues Paper we explore the key drivers of the proposed increase in revenues and network tariffs. We have framed this discussion by reference to our Better Resets Handbook[1], which sets out our expectations for how a network business can engage with consumers and, our expectations (consistent with the NER framework) in topic areas such as capital expenditure (capex), operating expenditure (opex), regulatory depreciation and tariff structure statements, which tend to have the most significant impact on consumers.

Proposals that reflect consumer preferences, and which meet our expectations, are more likely to meet the requirements of the NER. They are therefore more likely to be largely or wholly accepted at the draft decision stage, creating a more effective and efficient regulatory process for all stakeholders.

In making this assessment we will have regard to the extent to which the proposals have been driven by, and now reflect, the preferences and priorities that Queensland electricity consumers have put to Ergon and Energex in their engagement on these proposals. Consumer engagement is an important factor in our assessment; however, we are still required to ensure we are satisfied that the proposed revenues reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs.

Together, these considerations support a decision that will ensure Queensland customers are paying no more than necessary for safe, reliable and secure delivery of their electricity distribution services.

[1] AER Better Resets Handbook – Towards consumer-centric network proposals

1.1 Our process

This Issues Paper sets out our initial observations on the proposals and some areas in which we are particularly interested to hear from stakeholders. Submissions in response to this Issues Paper will inform our draft decision in September.

The next step in our process, following the public forum on 11 April, is to make a draft decision in September 2024, setting out what parts of the proposals we consider can be accepted, and those that we consider cannot. If we disagree with Ergon and Energex on elements of their proposals, our draft decisions will substitute alternatives of our own and explain what we consider is required to address our concerns in revised proposals.

Ergon and Energex will then have an opportunity to submit revised proposals incorporating any changes, or addressing any matters, raised by the draft decisions. Both draft decisions and revised proposals will be open to consultation before we make our final decisions in April 2025.

An indicative timeline for our assessment of, and decision on, the proposals is set out below.

Table 1 Indicative timeline – Ergon, Energex determinations 2025–30

Milestone	Date
Issues Paper	26 March 2024
Public forum	11 April 2024
Submissions close	15 May 2024
Draft decisions	September 2024
Revised proposals due	December 2024
Submissions close	January 2025
Final decisions	April 2025
Final decisions take effect	1 July 2025

Note: The timing of these milestones is subject to change, but our process will ensure stakeholders are afforded all consultation periods required under cll. 6.10 and 6.11 of the NER.

1.2 Have your say

Consumer engagement is a valuable input to our determination. We have set out a number of questions throughout this paper. Stakeholders can assist in our process by providing their views on these or any other aspects of the proposals.

When we receive stakeholder submissions that articulate consumer preferences, address issues in a revenue proposal, and provide evidence and analysis, our decision-making process is strengthened.

You can contribute to our assessment by:

- Making a written submission on the proposal by close of business, 15 May 2024
- Joining us at an online public forum on 11 April 2024. Registration details are available on our website and through Eventbrite.

Written submissions should be sent electronically to energyqueensland2025@aer.gov.au and addressed to Gavin Fox, General Manager. Alternatively, you can mail submissions to GPO Box 3131, Canberra ACT 2601.

We ask that all submissions sent in an electronic format are in Microsoft Word or other text readable document form.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested. All non-confidential submissions will be placed on the AER's website.

We request parties wishing to submit confidential information:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy.

2 Initial observations

Energex's distribution network supplies electricity to South East Queensland including Brisbane, the Gold Coast and Sunshine Coast. Ergon's distribution network supplies North, Central and Southern Queensland. Where the Energex network largely services areas with high population density, large parts of the Ergon network service rural areas with much lower population density per network kilometre.

Despite these differences, both revenue proposals have a similar trajectory, and the drivers are largely common to both networks (section 2.2 below)

Ergon's proposal would allow it to recover $8,522.3 million ($nominal, smoothed) from its customers over the 2025–30 period.[2] This is 43.1% higher than what we approved for the 2020–25 period.[3] Energex's proposal would allow it to recover $8,897.8 million ($nominal, smoothed) from its customers over the 2025–30 period.[4] This is 46.8% higher than what we approved for the 2020–25 period.[5]

Energex's proposed revenue forecast is used to determine the charges for the distribution network component of the electricity bill for its customers. The cost of the distribution network component of the electricity supply chain makes up about 22% of the average electricity bill for residential customers and 21% for small business customers in the Energex network and are ultimately recovered through electricity retail charges.[6] For illustrative purposes, Energex estimates that over the next 2025–30 regulatory period its proposal would result in:

- an average annual increase of $42 for residential customers or a 2.0% increase
- for small-medium business customers, which use more electricity, an average annual increase of $85 or a 1.9% increase.[7]

The bill impact calculations for Ergon are the same as Energex. This is because retail electricity prices in Ergon's distribution area are determined under the Queensland Government's uniform tariff policy. The policy sets retail electricity prices in Ergon's distribution area in line with those in Energex's area.[8]

Ergon and Energex's proposals represent the first step in a 15-month review process. Over the course of this process, as we move from proposal to draft decision, and then to revised proposal and final decision, components of forecast revenue are likely to change. These changes may result in us taking a different view of the revenues proposed by Ergon and

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2 This is SCS revenue exclusive of legacy metering which is $179.7 million (nominal).

3 In real terms ($2024–25), proposed total revenue is $1072.2 million (15.9%) higher than approved for 2020–25 period.

4 This is SCS revenue exclusive of legacy metering which is $394.4 million (nominal).

5 In real terms ($2024–25), proposed total revenue is $1307.2 million (19.1%) higher than approved for the 2020–25 period.

6 Energex, *Energex - RIN.05 - Indicative Bill Impacts*, January 2024.

7 Based on SCS revenue exclusive of legacy metering. Energex, *Energex - RIN.05 - Indicative Bill Impacts*, January 2024.

8 Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for 2023–24*, June 2023, p. 9.

Energex. In addition, a standard part of our process is to update the forecast revenue for movements in market variables such as interest rates, bond rates and inflation.

Movements in these market variables can have a material impact on the final revenue and, therefore, consumer bills. Consequently, projected bill impacts at this stage should be treated as no more than potential impacts subject to changes in interest rates and inflation.

2.1 Key drivers of proposed revenue

Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditures) in real terms. Over time, inflation impacts the spending power of money. To compare revenue from one period to the next on a like-for-like basis, in this section we use 'real' values based on a common year (2024–25) that have been adjusted for the impact of inflation.

In real terms as shown in Figure 1, Ergon's proposal, if accepted, would allow it to recover $7,818.9 million ($2024–25, smoothed) from its consumers over the 2025–30 period or $1,081.3 million (16.0%) increase compared to the current 2020–25 period.. Figure 2 shows that Energex's proposal if accepted, would allow it to recover $8,161.1 million ($2024–25, smoothed) from its consumers over the 2025–30 period or $1,307.2 million (19.1%) increase compared to the current 2020–25 period

Figure 1 Changes in Ergon's regulated revenue over time ($million, 2024–25)

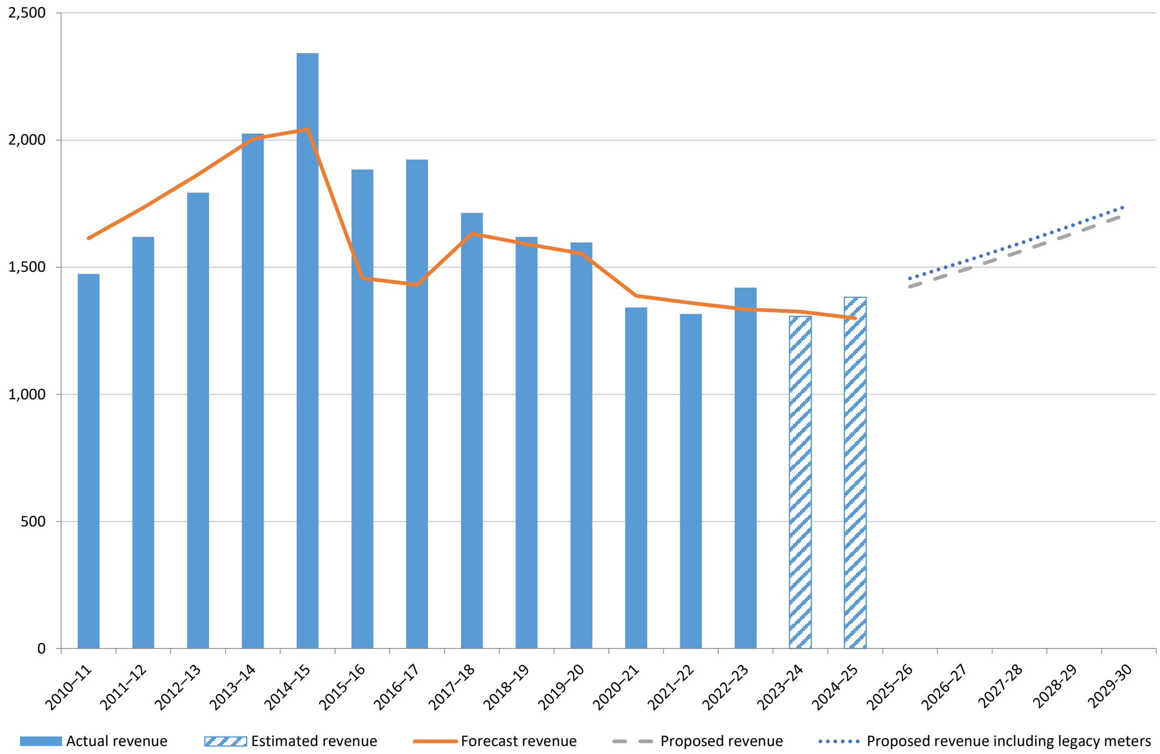
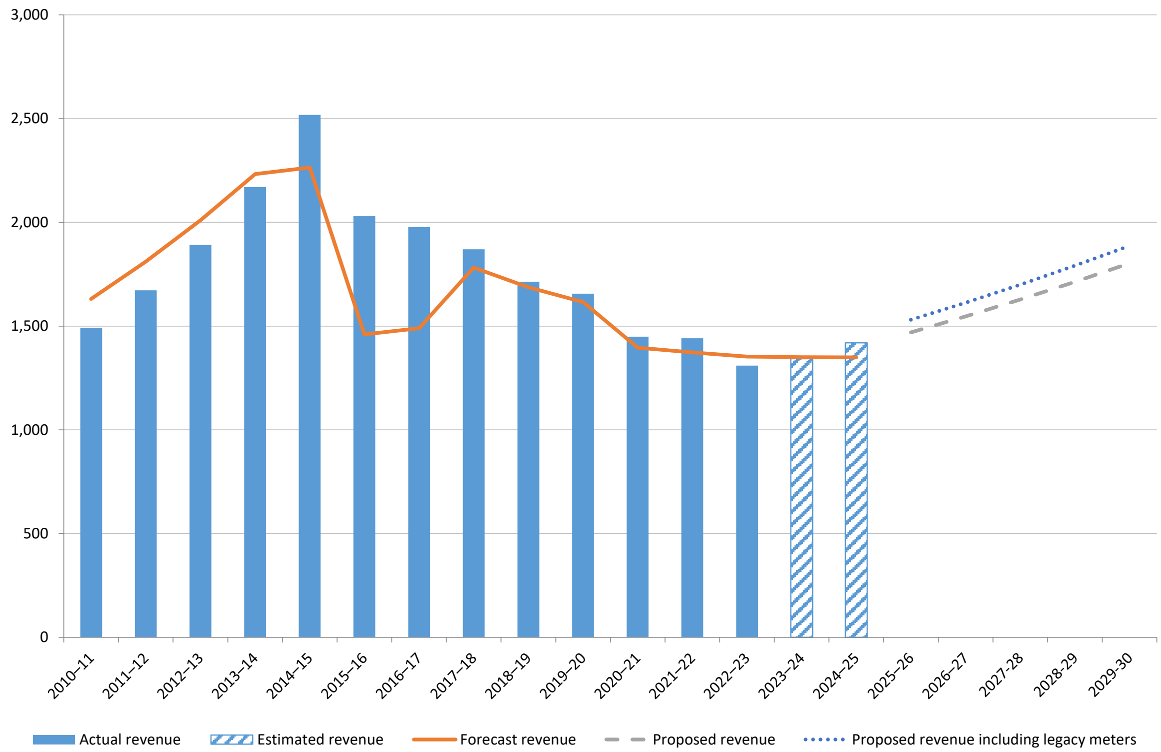


Figure 2 Changes in Energex's regulated revenue over time ($million, 2024–25)

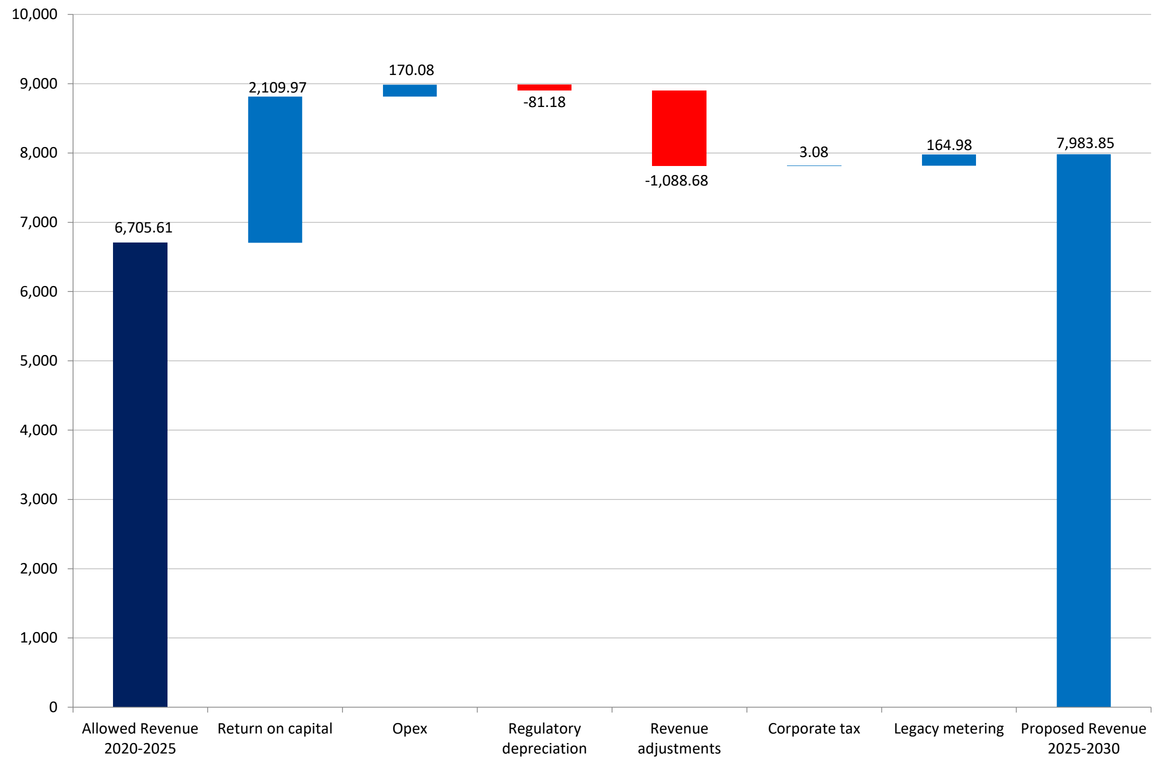


Source: AER analysis.
Note: Ergon and Energex have included in its proposed revenue legacy metering assets that it is proposing to move into standard control services. We have represented the revenues inclusive of these amounts in a separate (dotted) line.

Figure 3 and Figure 4 show the broad changes in revenue at the 'building block' level to illustrate what is driving Ergon and Energex's proposed total revenue increase from 2020–25 to 2025–30. Ergon and Energex state that the increase in their proposed revenue is driven primarily by rising interest rates and higher inflation as well as higher capital expenditure.[9]

[9] Energex, *Energex - 2025-30 Regulatory Proposal – 31 January 2024* -, p. 24; Ergon Energy, *Ergon - 2025-30 Regulatory Proposal – 31 January 2024*, p. 24

Figure 3 Changes in Ergon's revenue building blocks: 2020–25 to 2025–30 ($million, 2024–25)

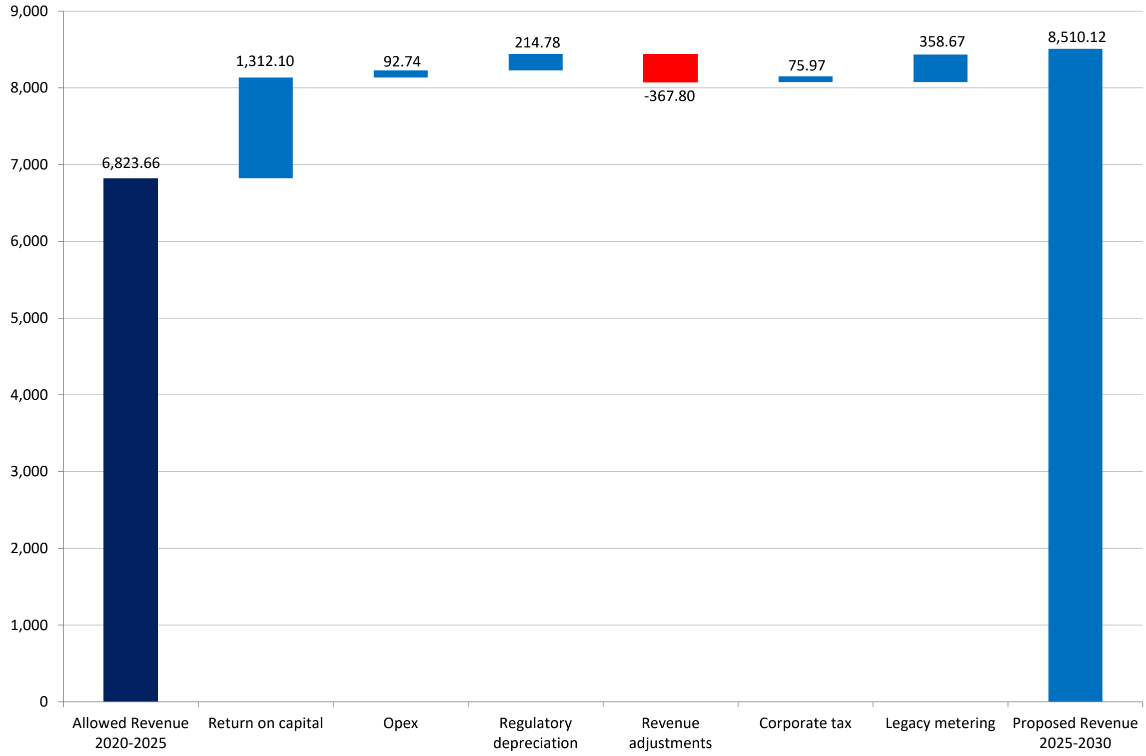


Source: AER analysis.
Note: Allowed revenue and proposed revenue in the chart are unsmoothed total revenue for the regulatory period. Ergon and Energex have included in its proposed revenue legacy metering assets that it is proposing to move into standard control services. We have noted its impact under 'Legacy Metering'.

The overall trend in Ergon's revenue is primarily driven by:

- Higher return on capital amount due to an increase in the opening RAB, higher rate of return and higher forecast capex. The increased opening RAB is due to higher actual inflation than forecast as well as actual capex exceeding forecast capex.
- Higher opex.
- Offsets to the above through a reduction to revenue adjustments reflecting EBSS and CESS penalties and lower regulatory depreciation compared to the 2020–25 period. Regulatory depreciation is the net total of straight-line depreciation less inflation indexation of the RAB. The straight-line depreciation has increased due to the higher capex in the 2020–25 period. However, the inflation indexation on the opening RAB increases by a greater amount due to the higher opening RAB as well as the continued growth of the RAB and higher expected inflation in the 2025–30 period, which more than offsets the increase in the straight-line depreciation. This results in a decrease to regulatory depreciation.

Figure 4 Changes in Energex's revenue building blocks: 2020–25 to 2025–30 ($million, 2024–25)



Source: AER analysis.
Note: Allowed revenue and proposed revenue in the chart are unsmoothed total revenue for the regulatory period. Ergon and Energex have included in its proposed revenue legacy metering assets that it is proposing to move into standard control services. We have noted its impact under 'Legacy Metering'.

The overall trend in Energex's revenue is primarily driven by:

- Higher return on capital amount due to an increase in the opening regulatory asset base (RAB), higher rate of return and higher forecast capex. The increased opening RAB is due to higher actual inflation than forecast as well as actual capex exceeding forecast capex.
- Higher regulatory depreciation due to an increase in forecast capex and a higher RAB value compared to the 2020–25 period.
- Higher opex.
- Higher cost of corporate tax due to higher return on equity.
- Offsets to the above through a reduction to revenue adjustments reflecting Efficiency benefit sharing scheme (EBSS) and Capital expenditure sharing scheme (CESS) penalties.

3 Consumer Engagement

Ergon and Energex supply an essential service to Queensland consumers. We expect them to submit high-quality, consumer-centric proposals driven by high quality consumer engagement. High quality consumer engagement will assist in developing proposals that are driven by consumer preferences. Further, high quality consumer engagement is critical to developing proposals that support delivery of services that meet the needs of consumers at a price that is affordable and efficient.

Our framework for considering consumer engagement in network revenue determinations is set out in the Better Resets Handbook, together with our expectations (consistent with the NER framework) in topic areas such as capital expenditure (capex), operating expenditure (opex) and regulatory depreciation which tend to have the most significant impact on consumers. Ergon and Energex are seeking 16% and 19% revenue increases respectively, driven by capex increases that are materially higher than both our approved forecasts for the current period and actual expenditure expected by the end of that period. This makes consumer buy-in for their proposed expenditure particularly important.

To gauge Ergon and Energex's progress on consumer engagement, it is worthwhile to revisit their 2020–25 regulatory reset process. We noted that the 2020–25 consumer engagement process was conducted in a "positive manner[10]" focused on four key themes identified in early consumer engagement. Key company executives were also actively engaged in the consumer engagement process. We did, however, note that the AER's Consumer Challenge Panel (CCP14) deemed consumer engagement less effective on capex and structure of tariffs. Consumers also highlighted a lack of clarity on the bill impacts of Ergon and Energex's expenditure decisions.

3.1 Nature of engagement

The nature of engagement is about how networks engage with their consumers. Our expectations are that network businesses will sincerely partner with consumers and equip them to effectively engage in the development of their proposals. Our assessment of nature of engagement includes "sincerity of engagement", which we infer from the actions of the business's Board and executives. It also includes an evaluation of the opportunity for consumers to engage about the outcomes that matter to them[11].

Although Ergon and Energex's engagement programme started late, it was ambitious and notable for the high number of channels, meetings and activities delivered. Engagements were centred on the Reset Reference Group (RRG) but involved stakeholders such as the Voice of the Customer Panel and Customer Focus Groups. Consultation forums included RDP2025 Stakeholder Forums, Public Lighting Forums, Large Customer Forums and Retailer Forums[12]. This amounted to 171[13] engagement events and opportunities for Ergon

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[10] Ergon, *Final decision – 2020-25 Revenue Proposal, p.21*

[11] AER, *Better Resets Handbook*, December 2021, p.6

[12] Ergon, *2025-30 Regulatory Proposal*, 31 Jan 2024, p.53

[13] Ergon, *2025-30 Regulatory Proposal*, 31 Jan 2024, p.52

and 175 for Energex[14]. While these engagements were numerous and led by sincere and diligent consumer engagement and regulatory teams, they may have created a risk of engagement fatigue amongst consumers.

For sincerity of engagement, we note that there could have been opportunities for additional involvement by Ergon and Energex executives. This contrasts with the 2020–25 reset process where key executives were more actively involved in the consumer engagement process. Furthermore, there was limited opportunity for consumers to “set the agenda” during the current process. Despite affordability being a key consideration for consumers, they were not given the opportunity to put key revenue drivers (particularly capex) on the agenda and did not have access to the bill impacts of key drivers of proposed expenditure decisions. This made it more challenging for consumers to make informed choices on key expenditure areas.

3.2 Breadth and depth of engagement

Breadth and depth relate to the scope of engagement with consumers and the level of detail at which network businesses engage on issues. The breadth and depth of engagement also covers the variety of avenues used to engage with consumers.

Ergon and Energex’s breadth and depth of engagement fell short of Handbook expectations. Consumers did not guide the development of the proposals, but engaged on the topics that were presented to them in the limited time available. Although engagement was comprehensive on matters such as incentive schemes, public lighting, and tariffs, it did not cover the key drivers of revenue for the 2025–30 regulatory period. Additionally, affordability and value for money were key considerations for consumers, and required detailed engagement given current cost-of-living pressures. This in-depth engagement on affordability and value for money, however, did not take place. When contrasted with the 2020–25 reset process, Ergon and Energex have made progress on tariff matters but made less progress on bill impact transparency and continued to omit the biggest revenue driver, capex, from meaningful consultation.

3.3 Clearly evidenced impact

Clearly evidenced impact is about how a proposal represents and is shown to represent consumer views.

Ergon and Energex’s proposals summarise decisions that incorporate consumer preferences. In response to customers’ affordability concerns, Ergon Energy committed to self-funding the non-network ICT capex that fell outside our allowance. Additionally, both Ergon[15] and Energex[16] made changes to opex, including applying a 1% productivity factor to opex and capitalised overheads. Both networks also considered their tariff schedules in line with consumer feedback to “spread the benefits of renewable energy” across the customer base.

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[14] Energex, *2025-30 Regulatory Proposal*, 31 Jan 2024, p.52

[15] Ergon, *2025-30 Regulatory Proposal*, 31 Jan 2024, p.54

[16] Energex, *2025-30 Regulatory Proposal*, 31 Jan 2024, p.54

While these measures are welcome, they omit the key drivers of their revenue and, therefore, will have limited impact on consumers' affordability concerns. These limitations on pre-lodgement engagement are a matter of concern, but there is still value to be gained from targeted, high-quality post-lodgement engagement focused on key revenue drivers. Empowering consumers to meaningfully engage on key revenue drivers such as capex and opex, maximising engagement from Ergon and Energex executives, and ensuring that the resultant input influences its revised proposals will add significant value to this process.

Questions on consumer engagement

1) Do Ergon and Energex's proposals adequately reflect consumers' affordability concerns?
2) Have Ergon and Energex chosen the right topics to engage with consumers on?
3) To what extent do you consider consumers were able to influence the topics Ergon and Energex engaged on?
4) Are there topics that you would have preferred to consider in greater detail? Please give examples.

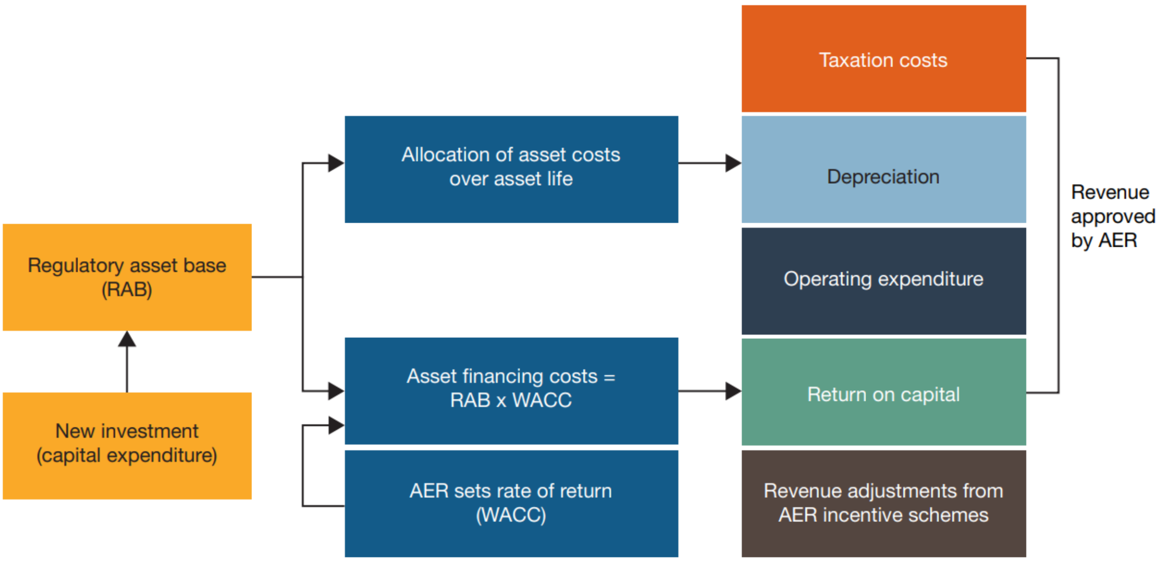
4 Key elements of the revenue proposal

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for a five-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. It delivers benefits to consumers as efficient costs are revealed and drive lower cost benchmarks in subsequent regulatory periods. By only allowing efficient costs in our approved revenues, we promote delivery of the NEO and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

The revenue Ergon and Energex have proposed reflects their forecasts of the efficient cost of providing distribution network services in their respective regions over the 2025–30 period. Their revenue proposals, and our assessment of them under the Law and Rules, are based on a 'building block' approach which looks at five cost components (see Figure):

- return on the RAB – or return on capital, to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the RAB – or return of capital, to return the initial investment to investors over time
- forecast opex – the operating, maintenance, and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements – resulting from the application of incentive schemes and allowances, such as the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and Demand Management Innovation Allowance Mechanism (DMIAM.)
- estimated cost of corporate income tax.

Figure 5 The building block model to forecast network revenue



Source: AER.

4.1 Rate of return and inflation

The return each business is to receive on its capital base ("return on capital") is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the RAB value.

We estimate the rate of return by combining the returns of two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and give a return on equity to investors.

The approach that will be taken to estimate the rate of return that applies to Ergon and Energex, including the return on debt, return on equity, and the value of imputation credits, is set out in our binding Rate of Return Instrument. We consult on and publish a new Rate of Return Instrument every 4 years. The Rate of Return Instrument that applies to these proposals was published in February 2023 after extensive consultation with stakeholders.[17]

Ergon and Energex's proposals for 2025–30 include a rate of return of 6.04 per cent, compared to 4.73 per cent in our 2020–25 decision. The increase in the rate of return is driven by the rise in interest rates since the last decision.

Ergon and Energex's proposals also include a higher expected inflation estimate for the 2025–30 period (2.80 per cent) compared to the estimate applied in our 2020–25 decision (2.27 per cent).

Together, these elements of our revenue determination are a significant contributor to the proposed revenue Ergon and Energex have proposed and add to the impact of higher past and forecast expenditure on the return on and of capital.

At this stage, these values are placeholders only. It is important that the proposals, and our decisions, update for the latest market data at each stage of the revenue determination process. By setting a rate of return that reflects current financial market conditions, our determinations will enable Ergon and Energex to attract the capital they need to provide the services that consumers want.

Moreover, the return investors receive on their assets should reflect the risks of their investment. These risks include the prospect of inflation eroding the investor's purchasing power. An allowance for expected inflation provides compensation for the risk to investors for the prospect of inflation eroding the investor's purchasing power. Figure 6 and Figure 7 respectively show the interaction of expected inflation on the forecast building block revenue.

- The return on capital building block applies a nominal rate of return to the RAB. As the nominal rate of return includes expected inflation, part of that building block compensates for expected inflation. Higher expected inflation increases the return on capital mainly due to RAB and capex.
- The return of capital building block removes expected inflation indexation of the RAB from forecast depreciation. This avoids compensation arising from the effects of inflation being double counted by including it in the return on capital building block and also as a

17 AER - Rate of Return Instrument (Version 1.1) - August 2023

capital gain (through the indexation of the RAB). Higher expected inflation therefore reduces the regulatory depreciation allowance.

- Other building blocks (such as operating expenditure or opex, and revenue adjustments) include an inflation component, as the costs forecast in real dollar terms are escalated to nominal dollars using expected inflation in determining the required nominal revenues. Higher expected inflation will increase opex and revenue adjustments.

Figure 6 Ergon: Inflation in revenue building blocks ($million, nominal)

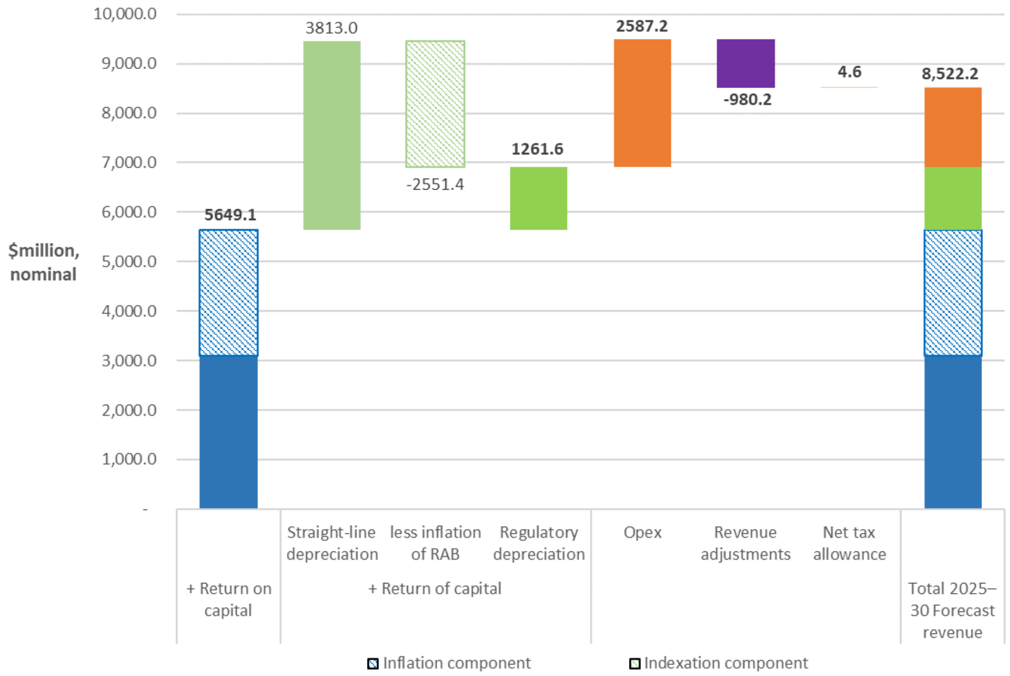
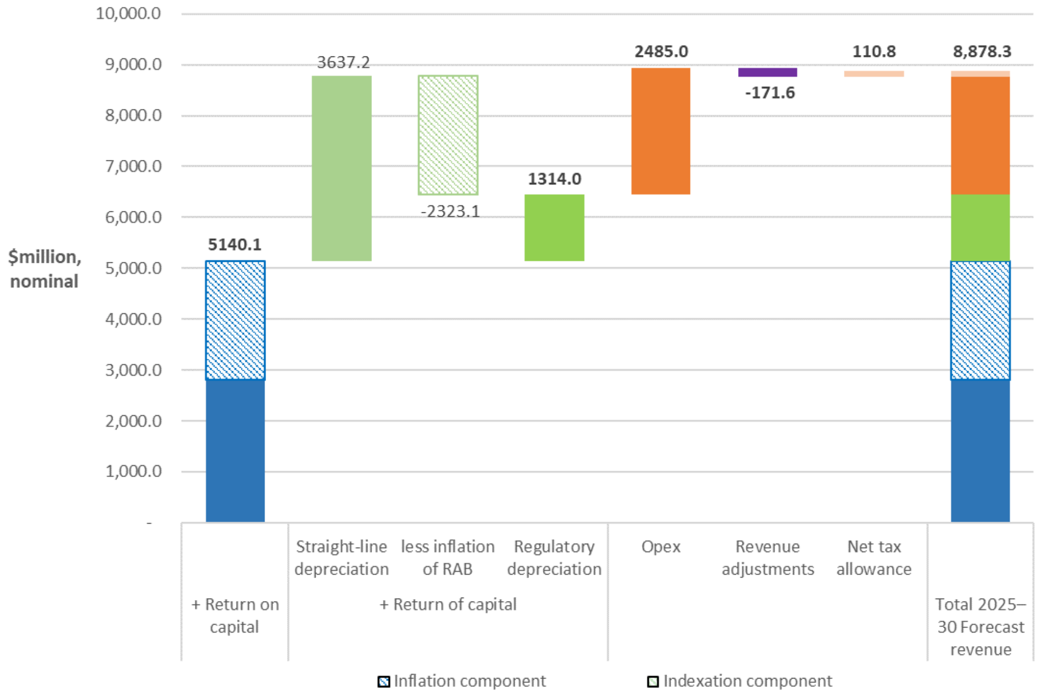


Figure 7 Energex: Inflation in revenue building blocks ($million, nominal)



Source: AER analysis.

4.2 Regulatory asset base and depreciation

The RAB is the value of assets used by Ergon and Energex to provide distribution network services. The value of the RAB substantially impacts the total revenue requirement, and the price consumers ultimately pay:

- The return on the RAB—or return on capital—applies the rate of return discussed above to the RAB. It is included in regulated revenue to compensate investors for the opportunity cost of funds invested in this business.
- Depreciation of the RAB—or return of capital— is included in regulated revenue to allocate the cost of assets making up the RAB over their useful lives. It is the amount provided so capital investors recover their investment over the economic life of the asset.

Other things being equal, a higher RAB would increase both the return on capital and depreciation components of the revenue determination.

To set revenue for 2025–30, we take the opening value of the RAB from the end of the current, 2020–25 period and roll it forward annually by indexing it for expected inflation, adding new forecast capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the RAB at the end of each year of the 2025–30 period.

As set out in our Better Resets Handbook, we expect a network business:[18]

- To use the post-tax revenue model (PTRM), roll forward model (RFM), and depreciation tracking module (where relevant) we have published under the NER without amendments
- To apply the same asset classes from the last regulatory determination, and asset lives that reflect those approved in previous decisions.

Ergon proposed a forecast RAB of $21,388.6 million ($ nominal) by the end of the 2025–30 period, which is $5,135.6 million higher than the estimated RAB at the end of the 2020–25 period. This follows an increase of $4,719.2 million ($ nominal) in the estimated RAB over the 2020–25 period. This reflects the exclusion of ICT capex of $121.3 million.[19] Ergon also notes it is projecting to overspend a significant amount of network and non-network capex[20] over the 2020–25 period, increasing its RAB significantly compared to that forecast in the 2020–25 determination.[21]

In real terms ($2024–25), Ergon's proposed RAB will be $2,377.4 million higher by the end of the 2025–30 period, driven by higher forecast capex.

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18 The Handbook records these expectations for depreciation proposals along with those for capex, opex and tariff structure statements. Proposals that meet these expectations are more likely to be largely or wholly accepted at the draft decision stage, creating a more effective and efficient regulatory process for all stakeholders.

19 Ergon Energy, *Ergon - 2025-30 Regulatory Proposal* - 31 January 2024, p. 34.

20 $1,727.8 million for network capex and $282.3 million for non-network capex.

21 Ergon Energy, *Ergon - 2025-30 Regulatory Proposal* - 31 January 2024, pp. 33–35.

Energex proposed a forecast RAB of $18,040.1 million ($ nominal) by the end of the 2025–30 period, which is $2,449.4 million higher than the estimated RAB at the end of the 2020–25 period. This follows an increase of $2,716.2 million ($ nominal) in the estimated RAB over the 2020–25 period. This reflects the exclusion of ICT capex of $130.2 million.[22]

In real terms ($2024–25), Energex's proposed RAB will be $123.0 million higher by the end of the 2025–30 period, driven by higher forecast capex. Figure 5 and Figure 6 respectively show the value of Ergon's and Energex's RAB over time.

Figure 5 Ergon's closing RAB value over time ($million, 2024–25)

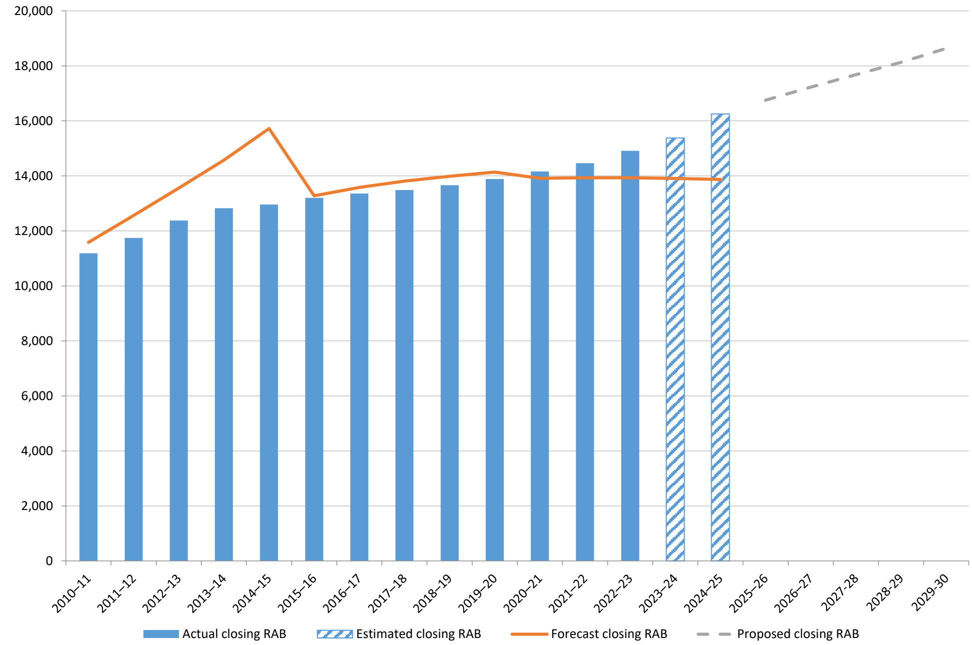
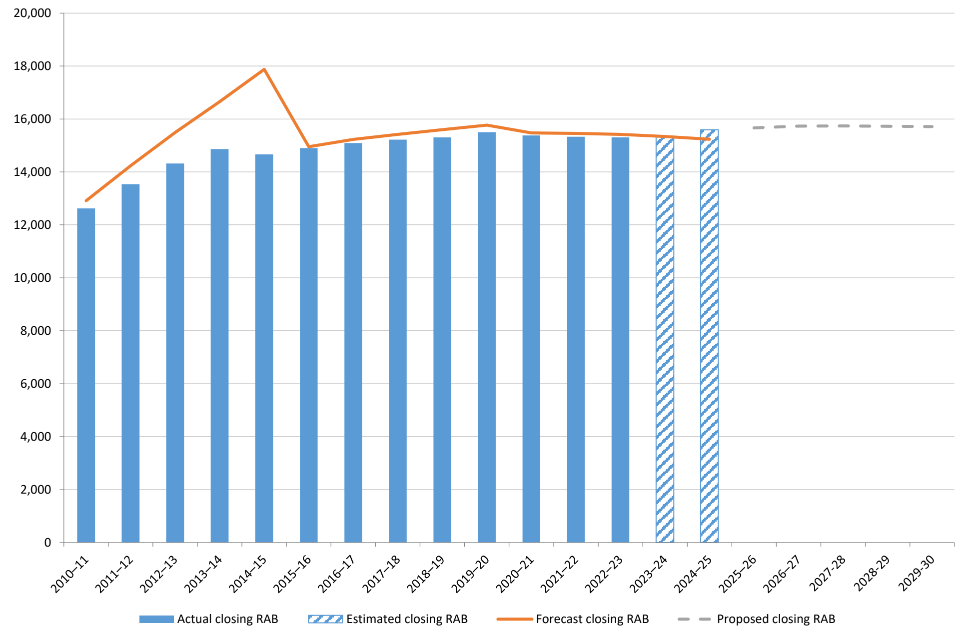


Figure 6 Energex's closing RAB value over time ($million, 2024–25)



Source: AER analysis.

22 Energex, *Energex - 2025-30 Regulatory Proposal* - 31 January 2024, p. 34.

Regulatory depreciation is provided so investors recover their investment over the economic life of the asset ("return of capital"). Ergon proposed regulatory depreciation of $1157.1 million ($2024–25) for the 2025–30 period, which is $87.2 million (7.0%) lower than for the 2020–25 period. The lower regulatory depreciation is due to the inflation indexation on the opening RAB increasing at a greater rate than the increase to straight-line depreciation. While the increase in straight-line depreciation is due to the addition of capex over the 2020–25 period, the higher inflation indexation on the opening RAB is driven by a significantly higher opening RAB as well as the continued growth of the RAB and higher expected inflation in the 2025–30 period, which more than offsets the increase in the straight-line depreciation.

Energex proposed regulatory depreciation of $1,204.5 million ($2024–25) for the 2025–30 period, which is $210.0 million (21.1%) higher than for the 2020–25 period. The higher regulatory depreciation is primarily driven by:

- A significant increase in forecast capex for the 2025–30 period.
- A higher opening RAB as at 1 July 2025 compared to the value we forecast in the 2020–25 determination. This is caused by a significantly higher actual/estimated inflation rates over the years 2021–25 than what was expected at the time of the 2020–25 determination.

Consistent with the expectations set out in the Handbook we note Ergon and Energex have:

- Used our standard regulatory models which includes the PTRM, RFM, and depreciation tracking module without amendments.
- Adopted the standard asset lives for their existing asset classes that are consistent with our 2020–25 determinations.

Ergon and Energex also proposed to continue with the year-by-year tracking for implementing straight-line depreciation, consistent with our 2020–25 determinations.

Ergon and Energex each proposed two new asset classes for allocating expenditures associated with capitalised leases due to a change to accounting standards for the treatment of leases. The new asset classes are in relation to property leases. The proposed new asset classes and the standard asset lives are:

- Initial leases (10 years standard asset life) – This asset class covers leases pertaining to their existing office sites at Townsville and Cairns.
- Lease extensions (5 years standard asset life) – This asset class covers the lease extensions of the above sites.

Based on our initial review, we consider Ergon and Energex's proposed standard asset lives for the new capitalised leases asset classes is appropriate as they are largely consistent with the average terms of their office leases.

We will assess Ergon and Energex's forecast expenditure to ensure that the various proposed asset lives remain appropriate for the nature of the capex.

4.3 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain, or improve the physical assets needed to provide standard control services.[23] Generally, these assets have long lives, and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Ergon and Energex are required to propose the total forecast capex they consider is required to meet or manage expected demand, comply with all applicable regulatory obligations, and to maintain the safety, reliability, quality, and security of each of their respective networks (the capex objectives).[24] We must decide whether or not we are satisfied that these forecasts reasonably reflect prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[25] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the NEO).[26] Our *Capital expenditure assessment outline for electricity distribution determinations*[27] explains our and distributors' obligations under the NEL and NER in more detail. It also describes the techniques we use to assess distributors' capex proposals against the capex criteria and objectives.

The handbook sets our expectations for capex forecasts. In summary:

- the business should demonstrate that the proposed expenditure is not significantly above current period spending, and the components of capex should be well-justified, consistent with past spending for recurrent components, and, for repex, not materially above our repex model
- the business shows evidence of prudent and efficient decision-making on key projects/programs
- there should be evidence that the proposal aligns with industry risk management standards
- there should be evidence of genuine consumer engagement.

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23 See section 6 of this Issues Paper. These are services that form the basic charge for use of the distribution system.

24 NER, cl. 6.5.7(a).

25 NER, cl. 6.5.7(c).

26 NEL, ss. 7, 16(1)(a).

27 AER - AER capital expenditure assessment outline for electricity distribution determinations - February 2020

4.3.1 Ergon Energy

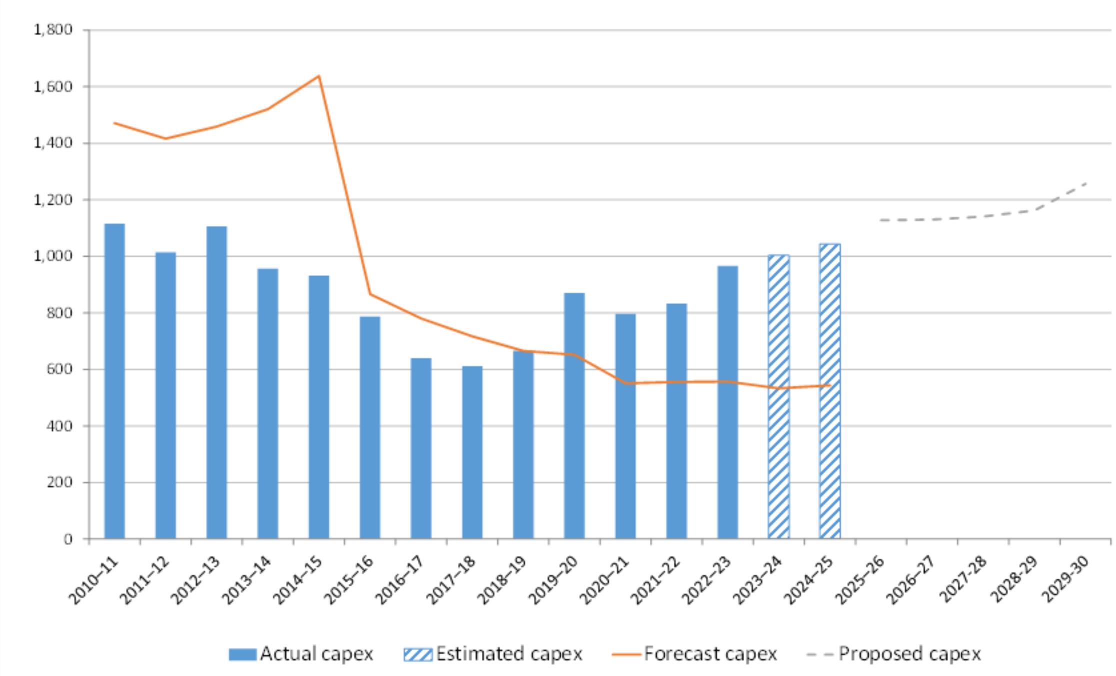
Ergon's forecast capex for the 2025–30 period is $5,805 million,[28] which is 20% higher than its expected capex for the 2020–25 period.[29]

Figure 7 presents the time-series of Ergon's net capex and shows Ergon expects to significantly overspend its capex forecast by about $2,057 million (74%) in the 2020–25 period.[30]

As can be seen, Ergon is forecasting to increase capex to the levels of expenditure in the 2020–25 period. We also observe that Ergon's 2020–25 period overspend is in contrast to its underspend in the last two preceding regulatory control periods.

Importantly, Ergon's actual capex is significantly higher than its capex forecast for the most recent five years for which it has actual data (2018–19 to 2022–23, or the ex post period). As we discuss in section 4.3.1.1, we will conduct an ex post review of this capex.[31]

Figure 7 Comparison of Ergon's past and forecast net capex ($million, 2024–25)



Source: AER analysis of Roll-forward model and Post-tax revenue model.
Note: Net capex subtracts capital contributions from gross capex, but it doesn't subtract disposals.

4.3.1.1 Ergon's capital expenditure from 2018–23

From one control period to the next, the RAB is updated to include actual capex incurred. Clause S6.2.2A provides that in certain circumstances we may reduce the amount by which a Distribution Network Service Provider's (DNSP) RAB is to be increased as part of the RAB

[28] Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 78.

[29] Ergon refers to this figure as 'net capex', but this excludes disposals. Once subtracting disposals, Ergon's total net capex is $5,783 million.

[30] Ergon - *2025-30 Regulatory Proposal* – 31 January 2024 – public, p. 85.

[31] AER - Final decision - Capital expenditure incentive guideline - 28 April 2023, pp. 12–19.

roll forward. One of these circumstances is that where a DNSP has spent more than its capex forecast (‘the overspending requirement’), we may exclude capex above the forecast from the RAB if, after an ex-post review, we consider it does not reasonably reflect the capital expenditure criteria.

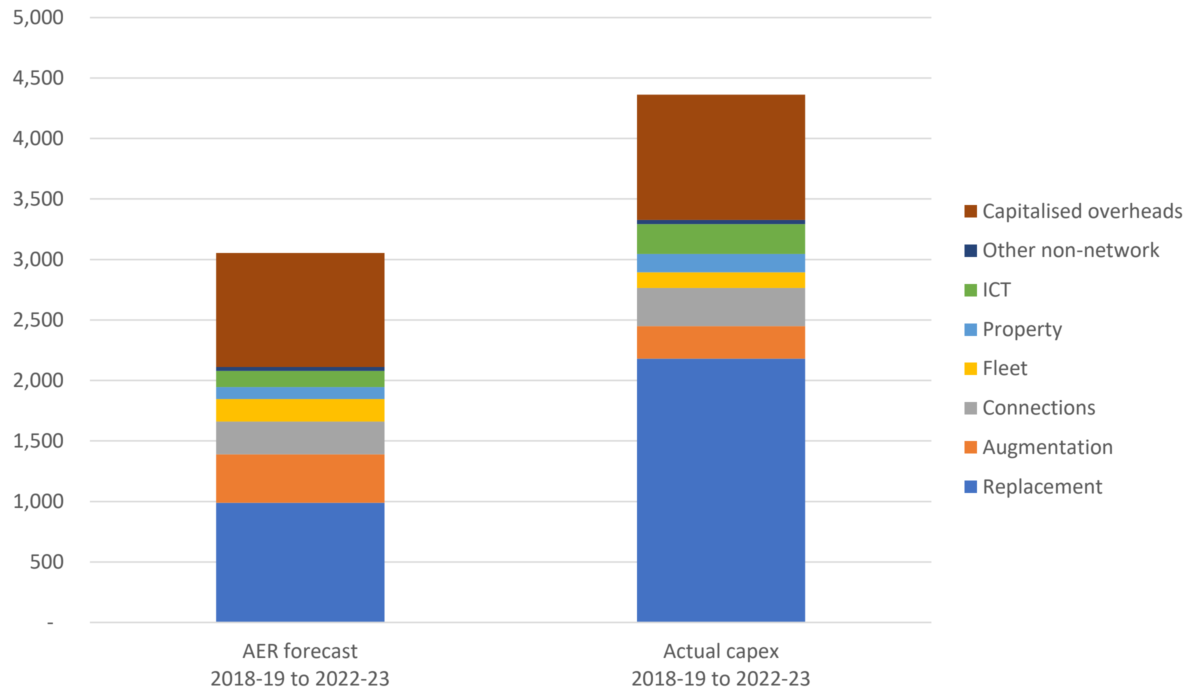
The ex-post review of Ergon’s capex will be a key focus for this revenue determination.

The relevant period over which this ex-post assessment is to occur is based on the availability of actual capex data at the time of the proposal: it comprises the first three years of the current regulatory control period and the last two years of the preceding regulatory control period. For Ergon, this period is 2018–23.

The AER’s Capex Expenditure Incentive Guideline for Electricity Network Service Providers sets out the ex-post review process.[32] The first stage considers the materiality of the overspend and whether there are any significant concerns. If the DNSP’s capex overspend warrants further assessment, stage 2 involves a deeper bottom-up review of the capex overspend.

Figure 8 compares the AER’s forecast capex and Ergon’s actual capex for the ex post period by category.

Figure 8 AER forecast and Ergon actual net capex for the ex-post period



Source: Ergon - 2025–30 Regulatory Proposal - January 2024 – public, p. 85.

For the ex-post period, Ergon’s actual capex is $1,309 million (43%) higher than the AER’s forecast. As can be seen in Figure 11, the main drivers are repex with an overspend of

[32] AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023, p.13-19

$1,191 (120%) and non-network ICT, with an overspend of $114 million (86%). Other areas of overspend are in connections and property.

Ergon stated it does not intend to recover the expenditure on ICT capex above the amount that was included in the AER forecasts for the ex post period.[33]

For repex, we understand that one of the drivers of the overspend is accelerated pole replacement, with the material step up in repex to be maintained over the forecast (2025-30) period. This means that our ex-post review will have implications for our review of Ergon's ex-ante 2025-30 forecasts.

Overall, we have assessed that at the total forecast capex level, Ergon has satisfied stage 1 of the ex-post review process; that is, that its total capex overspend is material such that further assessment is warranted especially the overspend in repex.

When the overspend is reviewed at the category level, repex contributes the most to capex during the ex-post period, and the overspend is the largest in repex. In this regard, a closer bottom-up review especially of repex at the stage 2 level is warranted.

Our bottom-up review at stage 2 of the ex-post review would involve consideration of, amongst other things:

- what the main drivers of the overspend were and reasoning for the variation between actual costs and the forecast.

  This will include a review of changes in unit costs and volumes as well as Ergon's asset management and governance arrangements. One of our focus areas will be the reasoning for the material pole volume increase given that this is a major driver of the overspend in its pole replacement.

- whether Ergon applied appropriate project management and planning processes; and

  Good project and portfolio management involves having a solid understanding of the actual costs of the projects and programs as well as managing the key risks of cost overruns during the regulatory period. We would review internal governance documents to assess whether Ergon followed internal procedures for those areas of overspend.

- whether the overspend was justifiable, and if it is not, how much of the overspend is not efficient and prudent.[34]

We also note that our findings in our ex-post review may have implications for our ex-ante review especially where there are underlying systemic changes in business practices that impact the forecasting approach.

4.3.1.2 Forecast capital expenditure for 2025–30

Ergon submitted that customer views around maintaining current levels of reliability and safety of the network have informed its capital investment program.[35]

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33 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024 – public, p. 87.

34 AER - Final decision - Capital expenditure incentive guideline - 28 April 2023, pp. 12–19.

35 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 78.

Table 2 sets out the composition of Ergon's capex proposal. The main driver is repex, contributing 44% to the total capex forecast. Except for ICT, Ergon forecasts an increase for all capex categories compared to the 2020–25 period. Ergon also proposed distributed energy resources (DER)[36] as a separate capex category, having been part of augmentation capex in the 2020–25 period.

We outline Ergon's proposed capex categories in the sections below, including its forecasting approach, key drivers, as well as areas of focus for our assessment.

Table 2 Ergon's 2025–30 net capex proposal compared to 2020–25 ($million, 2024–25)

Driver	2020–25 forecast	2020–25 actual/ estimate	2020–25 actual/ estimate vs forecast (%)	2025–30 proposal	2025-30 proposal vs 2020-25 actual (% change)	2025–30 proposal (% of net capex)
Replacement	1,079	2,352	118%	2,579	10%	44%
Augmentation	256	439	71%	789	80%	14%
Connections	251	321	28%	321	0%	6%
Fleet	156	171	10%	243	42%	4%
Property	79	142	80%	175	23%	3%
ICT	197	400	103%	288	-28%	5%
DER	n/a	n/a	n/a	63	n/a	1%
Other non-network	27	27	0%	32	16%	1%
Capitalised overheads	739	986	33%	1,316	33%	23%
Net capex	**2784**	**4,838**	**74%**	**5,805**	**20%**	**100%**

Source: AER analysis
Note: Net capex subtracts capital contributions from gross capex, but it doesn't subtract disposals.

36 We more commonly refer to DER as consumer energy resources (CER) because consumer-owned DER such as rooftop solar are the main drivers of network costs at this stage.

Replacement expenditure (repex)

Ergon proposed repex of $2,579 million, which is 10% higher than its current period spend. We note Ergon expects to overspend its repex forecast for the 2020–25 period by $1,273 million (or by 118%). This indicates that Ergon expects to maintain the higher level of repex it has incurred in the current period.

Ergon stated that this proposal is in line with its long-term historic average for replacement and is a continuation of its existing asset management practices.[37] Ergon stated it took prudent actions to extend the lives of its assets between 2010 and 2017. However, a substantial number of assets are reaching end of life in the 2020–25 and 2025–30 periods, so Ergon cannot continue to avoid replacing these assets due to safety and reliability impacts.[38]

Ergon noted its forecast repex is mainly driven by the asset management objectives in its Strategic Asset Management Plan[39] and its application of the Cost Benefit Framework and Principles[40].

We note that Ergon's modelled repex is 62% of its total repex.[41] Ergon stated it used the AER's repex model as a tool for a top-down challenge and check of repex forecast requirements, mainly at an overall repex level rather than at an asset category level.[42] The AER's repex model is typically used as a top-down tool to assess a DNSP's forecast modelled replacement expenditure against all other DNSPs.

We engaged with Ergon at the pre-lodgement phase about the running of the repex model. We found that engagement to be constructive, with Ergon being responsive to our queries.

We note that Ergon's proposed expenditure is higher than the AER repex model by 17 per cent.[43] We came to similar findings in our preliminary run of the repex model,[44] however we note some differences in modelling assumptions and intend to review and engage with Ergon further on these.

Augmentation capex (augex)

Ergon proposed augex of $789 million for the 2025–30 period. This is 80% higher than actual/estimated expenditure in the current period. We note Ergon expects to overspend its augex forecast for the 2020–25 period by $183 million (or by 71%).

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37 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 89.

38 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 90.

39 Ergon - *5.2.04 - Strategic Asset Management Plan (SAMP)* - January 2024.

40 Ergon - *5.2.05 - Cost Benefit Framework and Principles* - January 2024.

41 Calculated from the modelled repex categories in Reset RIN table 2.2 and Ergon's total replacement program including resilience and OTI.

42 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p.91.

43 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 91–92.

44 It suggested Ergon's proposed expenditure is 21% higher than the repex model.

Major components of Ergon's proposal include augex on its sub-transmission ($183 million) and distribution ($215 million) networks due to population and customer growth.[45] Ergon also proposed $181 million for its Clearance Programs[46] and $129 million for "Grid communications, protection and control".[47]

Ergon stated its augex proposal is in line with its long-term historic average and reflects the challenges of a geographically dispersed, ageing network in times of forecast demand growth.[48]

Ergon's augex forecasts also included $58 million for its resilience program. Ergon submitted that estimated costs for this program are based on an assessment of the likely number of at-risk areas, utilising flood and bushfire mapping and historic outage data, and an assessment of historic costs for projects of these types.[49]

We will review Ergon's resilience proposals having regard to the AER's guidance note on network resilience, which we released in April 2022 to provide certainty to stakeholders on how we would treat resilience-related expenditure under the NER.[50]

Connections capex

Ergon proposed gross connections capex of $406 million for the 2025–30 period, or $321 million of net connections capex (gross connections capex minus capital contributions). The proposed net connections proposal is approximately the same amount that Ergon expects to spend in the 2020–25 period. We note Ergon expects to overspend its net connections capex forecast for the 2020–25 period by $70 million (or by 28%).

Ergon stated its proposed connections capex reflects the expected strong population growth in regional Queensland.[51]

Ergon acknowledged there was scope to improve the top-down method it employed to forecast connection and contribution expenditure forecasts for the 2020–25 period. In response, Ergon stated it developed a robust econometric modelling approach for the 2025–30 period, consistent with the forecasting approaches of other distributors in the NEM.[52]

Distributed energy resources (DER)

Ergon proposed $63 million capex for its DER program.[53] Of this, approximately $36 million is for the "Grid visibility" program, which aims for greater access to timely data and information

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45 Ergon - *2025-30 Regulatory Proposal* - January 2024 – 31 January, pp. 101–102.

46 Ergon stated this program would address compliance obligations to ensure assets maintain a clearance to ground and surrounding structures within statutory limits.

47 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 103–104.

48 *Ergon - 2025-30 Regulatory Proposal* – 31 January 2024, p. 99.

49 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 103–104.

50 AER, *Note on the key issues of network resilience*, April 2022.

51 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 110; Ergon - 5.2.01 - Model - SCS Capex Model - January 2024 - public, J12 and J19.

52 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 111–112; Energex - 2025-30 Regulatory Proposal - January 2024, pp. 111–112.

53 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 107.

to determine the electrical status of the low voltage network. Ergon considers this program would better enable it to manage the growing volumes of DER in real time.[54]

Ergon stated DER is a new category of expenditure for the 2025–30 period, with expenditure of this nature being historically captured in augex. For its proposal for the 2025–30 period, Ergon clarified this expenditure category relates to network augmentation to resolve constraints associated with incorporating DER that exports energy into the distribution network. This could include rooftop solar but may also extend in time to electric vehicles with vehicle-to-grid capability, micro-wind or energy storage system exports.[55]

We will review Ergon's proposals having regard to our DER Integration Expenditure Guidance note and Customer export curtailment value (CECV) methodology.[56] Ergon indicated it had regard to the AER's CECV when developing its DER proposals.[57]

Information and Communications Technology (ICT)

Ergon proposed $288 million for ICT capex, which represents a 28% decrease from the 2020–25 period. Ergon expects to overspend its ICT capex forecast for the 2020–25 period by $203 million (or 103%).

Ergon submitted that after delivering a major ICT transformation in the current period, the focus of the 2025-30 period will shift to on-going maintenance.[58] Ergon stated it has learned that as legacy applications become older, they become exponentially harder to transform and consolidate. Hence, while Ergon's proposed non-recurrent ICT has decreased, its proposed recurrent ICT has increased significantly due to shifting to a continuous cycle of regular upgrades.[59]

Ergon also proposed cyber security capex. Amendments to the *Security of Critical Infrastructure Act 2018* now place obligations on distributors to implement and maintain a risk management program to address a range of prescribed risks including cyber security and physical security risks. Ergon submitted its cyber related information as confidential including the total capex amount for cyber-ICT.

Fleet capex

Ergon proposed $243 million in capex for its fleet of vehicle and trucks, which represents a 42% increase from the 2020–25 period.

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54 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 107–108.

55 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 105; Energex, *2025–30 regulatory proposal*, 31 January 2024, p. 106.

56 AER, *DER integration expenditure guidance note*, June 2022; and AER, *Customer export curtailment value methodology*, June 2022.

57 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 106; *Energex*, *DER Integration Strategy*, 31 January 2024, p. 16.

58 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 116; *Energex, 2025–30 regulatory proposal*, 31 January 2024, p. 115.

59 Ergon - *2025-30 Regulatory Proposal* - January 2024, p. 119; *Energex, 2025–30 regulatory proposal*, 31 January 2024, p. 119.

Ergon submitted that the key drivers for the uplift in fleet capex are investing in an ageing fleet, an increase in employee numbers, unit rates, and a change in replacement strategy for Elevated Work Platforms.[60]

We note that Ergon estimated a capex overspend of approximately $15 million on Fleet in the current period. Ergon stated this is due to several factors including higher than forecast increases in the unit cost of vehicles and an unanticipated increase in the number of light commercial vehicles required as a result of an increasing program of work.[61]

Property capex

Ergon proposed $175 million in capex for non-network property. This includes capitalised leases of $17 million, which is a new category for the 2025-30 regulatory control period.[62] Excluding this new category, Ergon's proposal is $157 million in capex for non-network property, which is 11% higher than the 2020–25 period.

Ergon submitted that the key drivers for the uplift in property capex are several major one-off projects to address capacity constraints and condition-based assessments.[63]

Non-network capex

Ergon proposed $32 million in capex for its tools and equipment, which represents a 16% increase from the 2020–25 period.

Ergon submitted that increased network programs, fleet and employee numbers are key drivers of the tools and equipment capex.[64]

Capitalised overheads

Ergon proposed $1,316 million in capitalised overheads, which represents a 33% increase from the 2020–25 period.

Ergon submitted that the forecast increase in capitalised overheads is due to the forecast increase in overall capex.[65] We acknowledge Ergon's proposal to promote affordability by applying a 1% productivity factor to capitalised overheads.

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60 Ergon - *5.9.06 - Non-network Fleet Plan 2025-30* -31 January 2024, p. 6; Energex, *Non-network Fleet Plan 2025–30*, 31 January 2024, p. 5.

61 Ergon - 5.9.06 - Non-network Fleet Plan 2025-30 – 31 January 2024, p. 5; Energex, *Non-network Fleet Plan 2025–30* - 31 January 2024, p. 4.

62 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 122–124.

63 Ergon - *5.9.01 - Non-network Property Plan 2025-30* – 31 January 2024, p. 4; Energex, *Non-network Property Plan 2025–30*, 31 January 2024, p. 3.

64 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 124; *Energex*, *2025–30 regulatory proposal*, 31 January 2024, p. 124.

65 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 128; *Energex, 2025–30 regulatory proposal*, 31 January 2024, p. 128.

Ergon's performance against the Better Resets Handbook capex expectations - areas of focus

Based on our preliminary assessment of Ergon's capex proposal, Ergon has not satisfied some aspects of the capex expectations of the Better Resets Handbook, and at this stage, there is insufficient information as to whether it satisfies some of the other capex expectations.

We intend to undertake a closer review of most aspects of its capex proposal, approximately 70% of its total capex proposal, because:

- its total capex forecast is 74% above 2020–25 period spend. Our review will focus on the areas which make up a material portion of the step up, this being in repex and augex, as well as new areas of expenditure like CER and cyber security expenditure.
- the step up in its total capex forecast relative to the current period spend appears to be in some recurrent expenditure areas like repex and fleet.
- it has materially overspent by 43% in the ex-post period which may have implications for our review of Ergon's ex-ante forecast.
- our preliminary run of the repex model at the pre-lodgement phase indicates that Ergon's modelled repex forecast is above the repex model threshold, indicating that it is not performing comparatively well against other electricity DNSPs on its unit costs or replacement lives or both; and
- at this stage, we are still assessing material Ergon submitted to assess whether it has provided sufficient evidence of prudency and efficiency on key projects and programs, whether its asset and risk management align with good industry practice, and whether there has been genuine consumer engagement on its capital expenditure proposal.

4.3.2 Energex

Energex's forecast capex for the 2025–30 period is $3,422 million,[66] which is 22% higher than its expected capex for the 2020–25 period.[67]

Figure 9 presents Energex's net capex and shows Energex expects to overspend its capex forecast by $357 million (15%) in the 2020–25 period.[68]

As can be seen, Energex is forecasting to increase capex to the levels of expenditure in the final two years of the 2020–25 period, where Energex is estimating to spend above the forecast. We also observe that Energex's projected overspend for the 2020–25 period (particularly for the final two years) is in contrast to its underspending in the last two preceding regulatory control periods.

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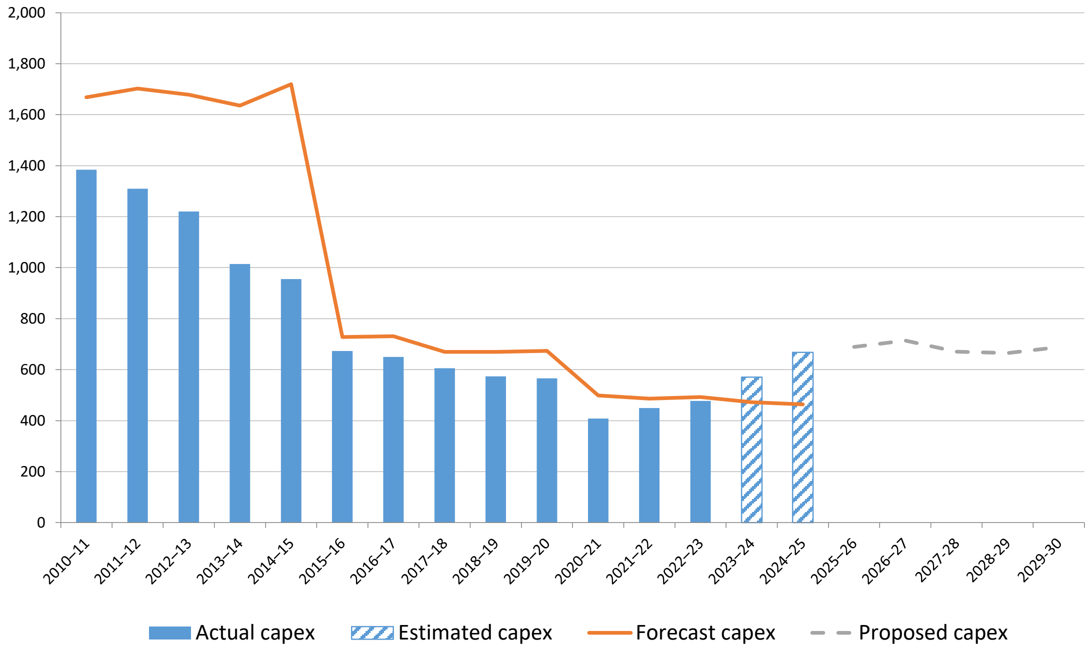
[66] Energex refers to this figure as 'net capex,' but this excludes disposals. Once subtracting disposals, Energex's total net capex is $3,408 million.

[67] Energex, *2025-30 regulatory proposal* - 31 January 2024, p. 80.

[68] Energex, *2025–30 regulatory proposal* - 31 January 2024, p. 86.

It is important to note that Energex's actual capex is 6% less than its capex forecast for the ex-post period (2018–19 to 2022–23). We will therefore not conduct an ex post review of this capex, unlike the case with Ergon (see section 4.3.1.1).

Figure 9 Comparison of Energex's past and forecast net capex ($million, 2024–25)



Source: AER analysis of Roll-forward model and Post-tax revenue model.
Note: Net capex subtracts capital contributions from gross capex, but it does not subtract disposals.

4.3.2.1 Forecast capital expenditure for 2025–30

As with Ergon, Energex submitted that customer views around maintaining current levels of reliability and safety of the network have informed its capital investment program.[69]

Table 2 sets out the composition of Energex's capex proposal. The main driver is repex, contributing 28% to the total capex forecast. Except for ICT, Energex forecasts an increase for all capex categories compared to the 2020–25 period. Energex also proposed DER as a separate capex category, having been part of augmentation capex in the 2020–25 period.

We outline Energex's proposed capex categories in the sections below, including its forecasting approach, key drivers, as well as areas of focus for our assessment.

69 Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 79.

Table 3 Energex's 2025–30 capex proposal compared to 2020–25 ($million, 2024–25)

Driver	2020–25 forecast	2020–25 actual/ estimate	2020–25 actual/ estimate vs forecast (%)	2025–30 proposal	2025-30 proposal vs 2020-25 actual (% change)	2025–30 proposal (% of net capex)
Replacement	760	853	12%	914	7%	28%
Augmentation	358	327	-9%	610	87%	18%
Connections	251	291	16%	362	24%	11%
Fleet	120	136	13%	199	46%	6%
Property	90	116	29%	152	31%	5%
ICT	176	397	126%	266	-33%	8%
DER	n/a	n/a	n/a	56	n/a	2%
Other non-network	11	19	73%	25	32%	1%
Capitalised overheads	675	659	-2%	838	27%	25%
Net capex	**2441**	**2,798**	**15%**	**3,422**	**22%**	**100%**

Source: AER analysis
Note: Net capex subtracts capital contributions from gross capex, but it doesn't subtract disposals.

Replacement expenditure (repex)

Energex proposed repex of $914 million, which is 7% higher than its current period spend. It submitted that customers believe its balance between cost and reliability is 'about right'.[70] Therefore, Energex focused on maintaining its current level of reliability using its existing asset management practices.

Energex proposed to bring forward some repex programs worth approximately $39.1 million from the 2030–35 regulatory control period. This is in response to the Brisbane 2032 Olympic and Paralympic Games. Energex stated it wants to ensure reliable and secure electricity during the event. It also anticipates an infrastructure pause in surrounding areas to Olympic venues during the lead up to 2032.[71]

70 Energex, *2025–30 regulatory proposal* - 31 January 2024, p. 88.

71 Energex, *2025–30 regulatory proposal* - 31 January 2024, p. 94.

Energex noted that its forecast repex is mainly driven by the asset management objectives outlined in its Strategic Asset Management Plan[72] and its application of the Cost Benefit Framework and Principles[73].

We note that Energex's modelled repex is 68% of its total repex.[74] Similar to Ergon, Energex stated that it used the AER's repex model as a tool for a top-down challenge and check of repex forecast requirements.[75]

We engaged with Energex at the pre-lodgement phase about the running of the repex model. We found that engagement to be constructive, with Energex being responsive to our queries.

Energex observed that its repex modelled forecast is lower than the threshold scenario.[76] We also came to these findings in our preliminary run of the repex model. However, we note some differences in modelling assumptions and intend to review and engage with Energex further on these.

Augmentation capex (augex)

Energex's proposed augex is $610 million. This is 87% higher than its current period spend. Energex submitted that the key drivers of augex are strong demand growth, compliance obligations, and network control and monitoring initiatives.[77]

Of the total proposed augex, approximately $360 million is for sub-transmission and distribution growth. Energex submitted that strong population and customer growth in Southeast Queensland means network growth investment is now required to ensure its customers receive reliable and secure supply.[78] Energex also proposed to bring forward $25 million of its growth investment relating to the Brisbane Olympic and Paralympic Games.[79]

Energex's augex forecast also includes $50 million for its resilience program. Energex utilised a similar method to Ergon to estimate costs for this program.[80] As with Ergon, we will review Energex's resilience proposals having regard to the AER's guidance note on network resilience.[81]

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72 Energex - *5.2.04 - Strategic Asset Management Plan (SAMP)* – 31 January 2024.

73 Energex - *5.2.05 - Cost Benefit Framework and Principles* – 31 January 2024.

74 Calculated from the modelled repex categories in Reset RIN table 2.2 and Energex's total replacement program including resilience and OTI.

75 Energex, *2025–30 regulatory proposal* – 31 January 2024, p.90.

76 Energex, *2025–30 regulatory proposal* – 31 January 2024, pp.90–91.

77 Energex, *2025–30 regulatory proposal* – 31 January 2024, p. 100.

78 Energex, *2025–30 regulatory proposal* – 31 January 2024, p. 101.

79 Energex, *2025–30 regulatory proposal* – 31 January 2024, p. 102.

80 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 103–104; *Energex*, *2025–30 regulatory proposal*, 31 January 2024, p. 104.

81 AER, *Note on the key issues of network resilience*, April 2022.

Connections capex

Energex proposed $362 million in net connections, which is 24% higher than its current period spend.[82] Energex submits the key drivers of its increase in net connections are population growth and decreasing household sizes.[83]

Like Ergon, Energex stated it developed a robust econometric forecast modelling approach for the 2025–30 period, acknowledging there was scope to improve its forecasting method for connections capex for the 2020–25 period.[84]

Distributed energy resources (DER)

Energex proposed $56 million capex for its DER integration strategy. Key drivers for Energex's proposed DER capex are investment in grid visibility and hosting capacity increases. It submitted that its DER integration strategy represents a medium paced investment scenario in response to customer feedback to take a proactive but balanced approach.[85]

Energex stated DER is a new category of expenditure for the 2025–30 period, with expenditure of this nature being historically captured in augex. Like Ergon, Energex clarified this expenditure category relates to network augmentation to resolve constraints associated with incorporating DER that exports energy into the distribution network.[86]

We will review Energex's proposals having regard to our DER Integration Expenditure Guidance note and CECV methodology.[87] Energex indicated it had regard to the AER's CECV when developing its DER proposal.[88]

Information and Communications Technology (ICT)

Energex proposed $266 million for ICT capex, which represents a 33% decrease from the 2020–25 period. Energex expects to overspend its ICT capex forecast for the 2020–25 period by $221 (or 126%).

Energex submitted that after delivering a major ICT transformation in the current period, the focus of the 2025–30 period will shift to on-going maintenance.[89] Like Ergon, Energex stated

82 This excludes $19 million in capital contributions that are recovered directly from customers.

83 Energex*, 2025–30 regulatory proposal* – 31 January 2024, pp. 112-113.

84 Energex, - *2025-30 Regulatory Proposal* – 31 January 2024 – public, pp. 111–112.

85 Energex*, 2025–30 regulatory proposal* – 31 January 2024, p. 110.

86 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024 – public, p. 105; *Energex, 2025–30 regulatory proposal* – 31 January 2024, p. 106.

87 AER, *DER integration expenditure guidance note*, June 2022; and AER, *Customer export curtailment value methodology*, June 2022.

88 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 106; *Energex*, *DER Integration Strategy* – 31 January 2024, p. 16.

89 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 116; *Energex*, *2025–30 regulatory proposal* – 31 January 2024, p. 115.

while its proposed non-recurrent ICT has decreased, its proposed recurrent ICT has increased significantly due to shifting to a continuous cycle of regular upgrades.[90]

Like Ergon, Energex also proposed cyber security capex noting amendments to the *Security of Critical Infrastructure Act 2018* now placing obligations on distributors regarding such risks. Energex submitted its cyber related information as confidential including the total capex amount for cyber-ICT.

Fleet capex

Energex proposed $199 million in capex for its fleet of vehicle and trucks, which represents a 46% increase from the 2020–25 period.

The key drivers for the uplift in Energex's fleet capex are similar to Ergon, including investing in an ageing fleet and an increase in employee numbers.[91]

We note Energex estimated a capex overspend of approximately $16 million on Fleet in the 2020–25 period. Like Ergon, Energex stated this is due to factors like higher than forecast increases in unit costs and an unanticipated increase in the number of light commercial vehicles required due to an increasing program of work.[92]

Property capex

Energex proposed $152 million in capex for non-network property. This includes capitalised leases of $14 million, which is a new category for the 2025–30 regulatory control period. [93] Excluding capitalised leases, Energex's proposal is $138 million in capex for non-network property, which is 19% higher than the 2020–25 period.

Energex submitted that the key drivers for the uplift in property capex are several major one-off projects to address capacity constraints and condition-based assessments.[94]

Non-network capex

Energex proposed $25 million in capex for its tools and equipment, which represents a 33% increase from the 2020–25 period.

Energex submitted that increased network programs, fleet and employee numbers are key drivers of the tools and equipment capex.[95]

Capitalised overheads

Energex proposed $838 million in capitalised overheads, which represents a 27% increase from the 2020–25 period.

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90 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 119; *Energex*, *2025–30 regulatory proposal*, 31 January 2024, p. 119.

91 Energex, *Non-network Fleet Plan 2025–30* – 31 January 2024, p. 5.

92 Energex, *Non-network Fleet Plan 2025–30* – 31 January 2024, p. 4.

93 Energex, - 2025-30 Regulatory Proposal – 31 January 2024 – public, pp. 121–122.

94 Energex, *Non-network Property Plan 2025–30* – 31 January 2024, p. 3.

95 Energex, *2025–30 regulatory proposal* – 31 January 2024, p. 124.

Energex submitted that the forecast increase in capitalised overheads is due to the forecast increase in overall capex.[96] We acknowledge Energex's proposal to promote affordability by applying a 1% productivity factor to capitalised overheads.

Energex's performance against the Better Resets Handbook capex expectations – areas of focus

Based on our preliminary assessment of Energex's capex proposal, Energex has not satisfied some aspects of the capex expectations of the Better Resets Handbook, and at this stage, there is insufficient information as to whether it satisfies some of the other capex expectations.

We intend to undertake a closer review of some aspects of its capex proposal, approximately 56% of its total capex proposal, because:

- its total capex forecast is 21% above current period spend. Our review will focus on the areas of which make up a material portion of the step up, this being in repex, augex, and connections as well as new areas of expenditure like CER and cyber security expenditure.
- the step up in its total capex forecast relative to the current period spend appears to be in some recurrent expenditure areas like repex and fleet.
- our preliminary run of the repex model at the pre-lodgement phase indicates that Energex's modelled repex forecast is below the repex model threshold, indicating that it is performing comparatively well against other electricity DNSPs on its unit costs or replacement lives or both; and
- at this stage, we are still assessing material Energex submitted to assess whether it has provided sufficient evidence of prudency and efficiency on key projects and programs, whether its asset and risk management align with good industry practice, and whether there has been genuine consumer engagement on its capital expenditure proposal.

Questions on forecast capital expenditure

5) Do you consider the AER's proposed approach to the ex-post review of Ergon's capex overspend is appropriate?
6) Do you consider Ergon and Energex's forecast capex for the 2025–30 period reasonably reflect the efficient costs of a prudent operator?
7) Are there particular areas of Ergon and Energex's capex proposals that you would expect further engagement on?
8) Are there particular areas of Ergon and Energex's capex proposals that you would expect we place greater focus on in our review?

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96 Energex, *2025–30 regulatory proposal* – 31 January 2024, p. 128.

4.4 Operating expenditure

Opex refers to the operating, maintenance and other non-capital expenditure incurred in the provision of network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require for the efficient operation of its network.

The Handbook sets our expectations for opex forecasts. In summary:

- the business will use our base-trend-step approach, including our standard assumptions
- step changes will be small in number and well-justified
- category specific costs will be small in number and well-justified
- there should be evidence of genuine consumer engagement.

Based on our initial assessment, Ergon and Energex's opex proposals adopt our base-trend-step approach. Ergon and Energex used estimated opex in 2023–24 for their base year. Noting affordability concerns of their customers, they applied base year efficiency adjustments of –2.3% and –5.9% respectively, and consistent with approaches in previous determinations made base adjustments of –2.8% and –4.3% of total forecast opex to remove costs associated with a jurisdictional scheme and changes to accounting standards. They both also forecast productivity growth over the 2025–30 regulatory control period of 1.0% per year, which is higher than our standard forecast of 0.5% per year. Further, they both proposed only one step change, comprising 0.3% and 0.6% of total forecast opex, respectively. Neither network has proposed category specific forecasts beyond debt raising costs, consistent with the approach in previous determinations.

Ergon and Energex noted that their opex proposals were shaped by consumer feedback emphasising consumer expectations that they maintain the safety, reliability and security of their networks while also considering affordability. Ergon and Energex stated that its opex forecast focused on maintaining its network to meet customer performance and service expectations in the most affordable approach. They explained that they responded to affordability concerns by making an efficiency adjustment to their base years, applying a 1.0% per year productivity factor, and reducing the number of proposed step changes.[97]

4.4.1 Ergon and Energex's opex proposals

Ergon's proposed total opex of $2,379.1 million ($2024–25), including debt raising costs, for the 2025–30 regulatory control period[98] is:

- $4.6 million ($2024–25) (0.2%) more than Ergon's actual/estimated opex for the 2020–25 regulatory control period
- $88.9 million ($2024–25) (3.9%) more than the opex forecast we approved for the 2020–25 regulatory control period.

Figure 13 shows Ergon's opex trend over time and the AER's approved opex forecast. Ergon's actual opex decreased significantly after 2015–16 to a level closer to the AER's forecast. Since then, its actual opex has and is forecast to remain relatively stable, but at

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97 Ergon, *2025–30 Regulatory Proposal* – 31 January 2024, pp. 131–132, 140, 142; *Energex*, *2025–30 Regulatory Proposal* – 31 January 2024, pp 130-131, 139, 141.

98 Ergon, *2025–30 Regulatory Proposal* – 31 January 2024, p. 132.

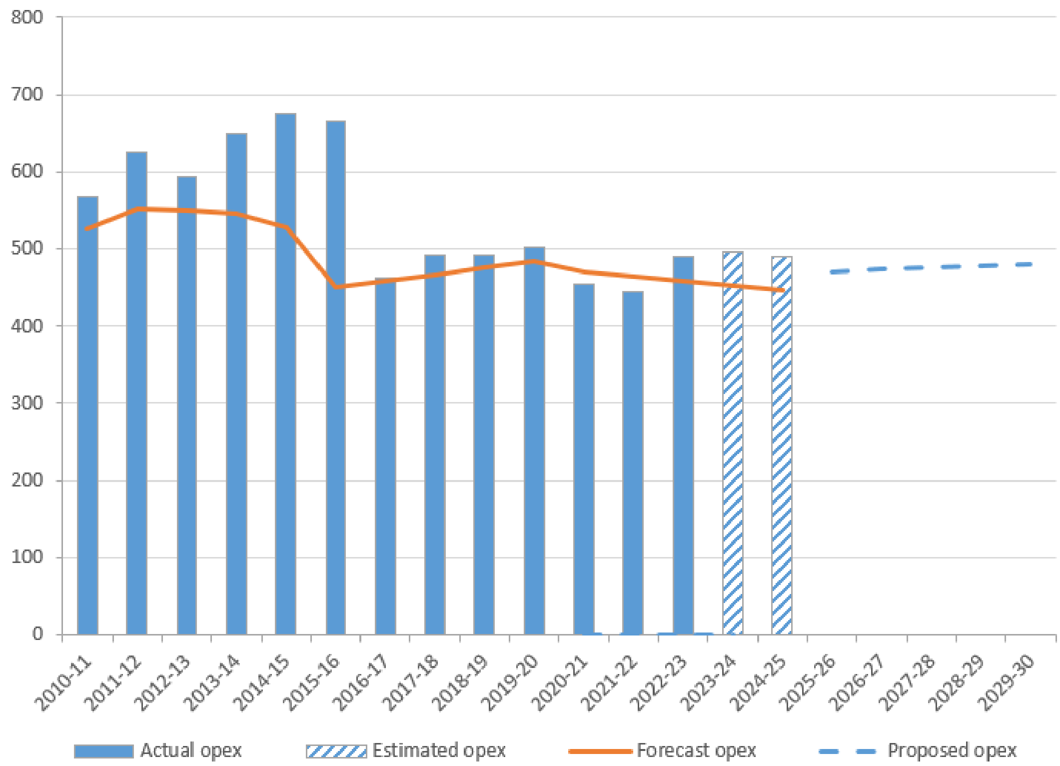
levels slightly above the AER forecast, apart from 2020–21 and 2021–22, where its actual opex was below our forecast.

Energex's proposed total forecast opex of $2,284.9 million ($2024–25), including debt raising costs, for the 2025–30 regulatory control period is:

- $163.7 million ($2024–25) (6.7%) less than Energex's actual/estimated opex for the 2020–25 regulatory control period
- $12.1 million ($2024–25) (0.5%) more than the opex forecast we approved for the 2020–25 regulatory control period

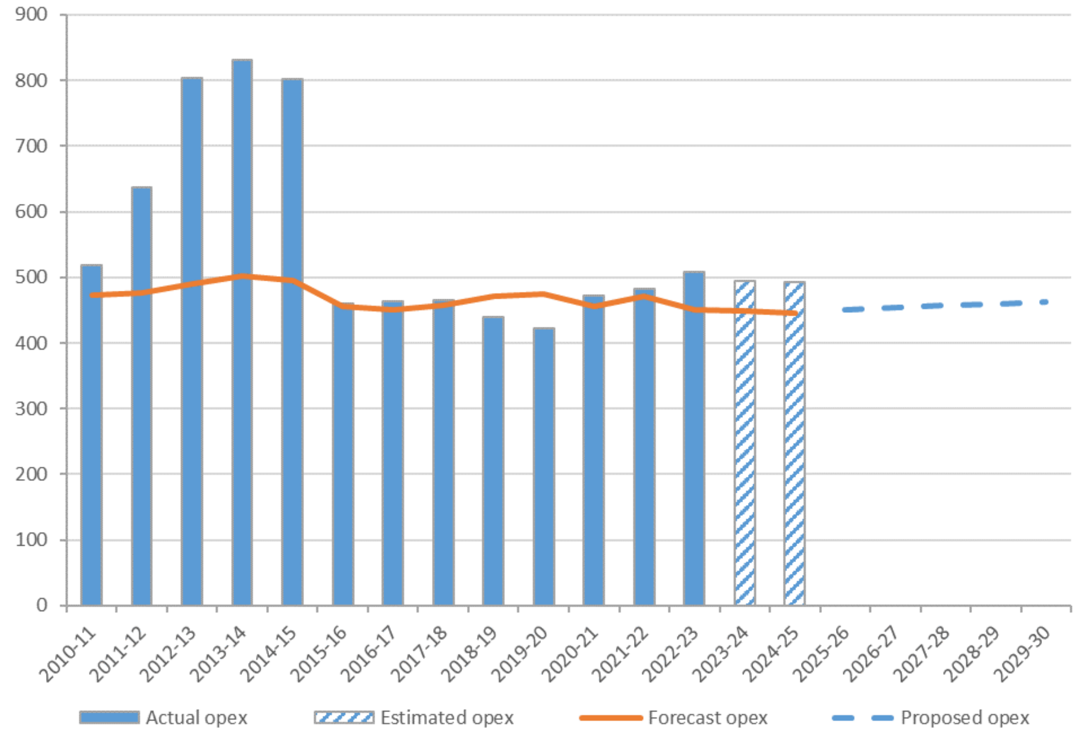
Figure 13 shows the trend in Energex's opex over time and the AER's approved opex forecast. Energex's actual opex decreased significantly after 2014–15 to a level closer to the AER's forecast and continued to trend downward to be less than the AER forecast in 2018–19 and 2019–20. Since then, Energex's actual opex has trended upwards and is forecast to remain above the AER forecast throughout the current regulatory control period.

Figure 13: Ergon's opex trend over time ($million, $2024–25)



Source: Ergon Energy Economic benchmarking – regulatory information notice responses 2010–23; AER, *Final decision PTRM 2010–15*; AER, *Final decision PTRM 2015–20*; AER, *Final decision PTRM 2020–25*; Ergon Energy, *Opex model,* Ergon Energy, 2024–29 Regulatory proposal; AER analysis.

Figure 14: Energex's opex trend over time ($million, $2024–25)



Source: Energex, *Economic benchmarking – regulatory information notice responses 2010–23*; AER, *Final decision PTRM 2010–15*; AER, *Final decision PTRM 2015–20*; AER, *Final decision PTRM 2020–25*; Energex, *6.02 – Model – SCS Opex Model,* 31 January 2024; AER analysis.

4.4.2 Key drivers of the opex proposals

Ergon and Energex used a base-step-trend approach to forecast their opex for the 2025–30 regulatory control period. This is consistent with our approach to assessing opex, as outlined in our *Expenditure Forecast Assessment Guideline*.[99]

Ergon used an estimate of opex of $496.2 million ($2024–25) in 2023–24 as the base year to forecast opex (or $2481.0 million ($2024–25) over the 2025–30 regulatory control period).[100] Ergon stated that it selected 2023–24 as its base year because it will be the most recent year of actual audited data available at the time of the final decision and it represents a realistic expectation of the efficient and sustainable on-going opex that it will require over the 2025–30 regulatory control period.[101]

Ergon then:[102]

- removed $55.3 million ($2024–25) for an efficiency adjustment, which Ergon stated was adopted to address affordability concerns of its customers.[103]

99 AER, *Expenditure Forecast Assessment Guideline*, November 2013.

100 Ergon*, 6.02 – Model – SCS Opex Model* – 31 January 2024.

101 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, p. 136.

102 Ergon*, 6.02 – Model – SCS Opex Model* – 31 January 2024.

103 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, p 131.

- removed $68.0 million ($2024–25) in base year adjustments, including $38.5 million for the Electrical Safety Office levy, which becomes a jurisdictional scheme in the 2025–30 regulatory control period, and $29.5 million ($2024–25) to reflect the treatment of property leases as capex rather than opex under a change to accounting standards.
- removed $30.7 million ($2024–25) to reflect the change in opex between the base year (2023–24) and the final year (2024–25), using the approach outlined in the *Expenditure Forecast Assessment Guideline*.
- removed debt raising costs of $30.4 million, which are forecast based on a benchmark rate.
- applied a rate of change comprised of:
  - forecast **output growth –** averaging 0.7% per year ($49.4 million ($2024–25)), based on the output forecasts and weights from our 2023 Annual Benchmarking Report,[104] consistent with our standard approach.
  - forecast **price growth** – averaging 0.7% per year ($51.8 million ($2024–25)), based on our standard approach of using a weighted average of forecast labour price growth and zero non-labour price growth.
  - forecast **productivity growth** – of 1.0% per year (-$68.7 million ($2024–25)). This is higher than our 0.5% per year standard productivity growth forecast.[105]
- added one step change of $6.8 million ($2024–25) (or 0.3% of total forecast opex) to acquire, process, and use smart meter data to increase visibility on its network and improve safety and reliability, integrate more renewables and reduce asset replacement costs.[106]
- added $43.1 million ($2024–25) for debt raising costs.

Figure 15 shows how each of these components contributes to Ergon's total opex forecast.

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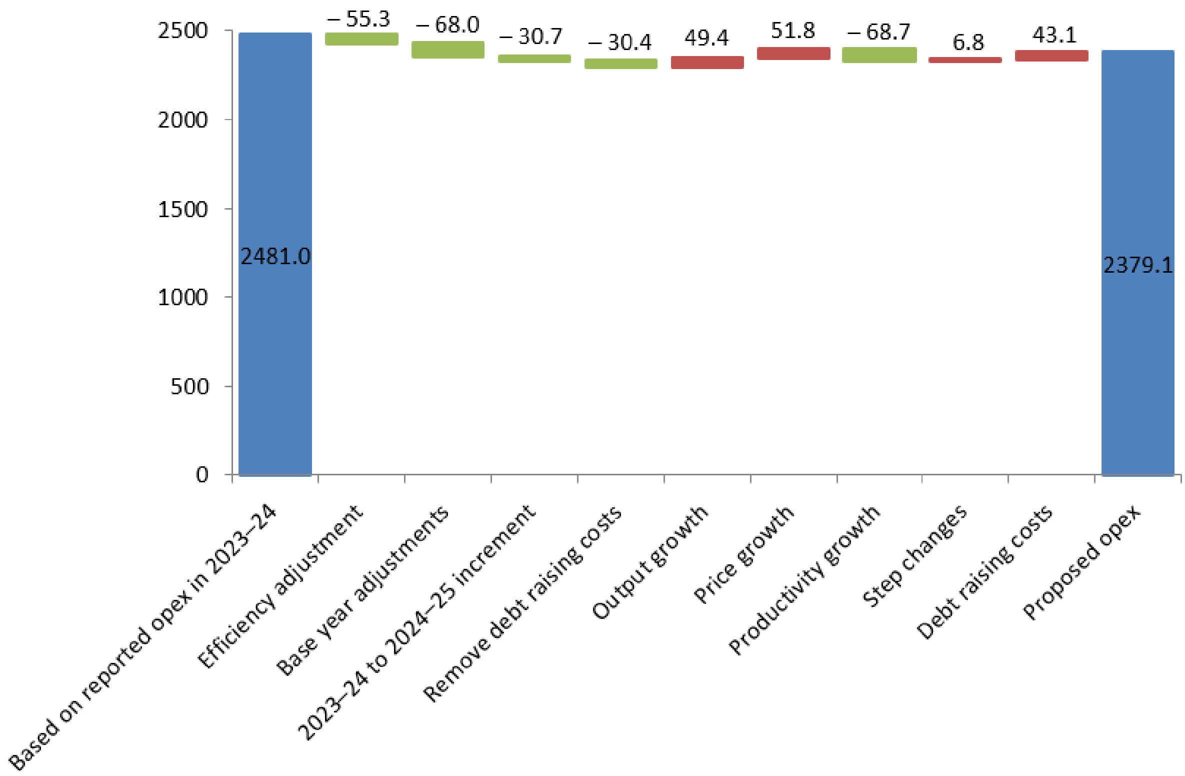
104 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, p 139.

105 The output, price and productivity growth dollar amounts used here differ slightly from Ergon's regulatory proposal because of a mechanical difference in calculating these trend components.

106 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, pp. 137–138.

Figure 15 Breakdown of Ergon's opex forecast ($million, $2024–25)



Source: Ergon, *6.02 – Model – SCS Opex Model,* 31 January 2024; AER analysis.

Energex also used, for the same reasons as Ergon, an estimate of opex of $494.8 million ($2024–25) in 2023–24 as the base year to forecast opex (or $2,474.0 million over the 2025–30 regulatory control period ($2024–25)).[107]

Energex then:[108]

- removed $138.9 million ($2024–25) for an efficiency adjustment, which Energex stated was adopted to address affordability concerns of its customers.[109]
- removed $101.7 million ($2024–25) in base year adjustments, including $68.2 million ($2024–25) for the Electrical Safety Office levy, which becomes a jurisdictional scheme for the 2025–30 regulatory control period, and $33.5 million ($2024–25) to reflect the treatment of property leases as capex rather than opex under a change to accounting standards.
- removed $12.7 million ($2024–25) to reflect the change in opex between the base year (2023–24) and the final year (2024–25), using the approach outlined in the *Expenditure Forecast Assessment Guideline*.
- removed debt raising costs of $32.4 million ($2024–25), which are forecast based on a benchmark rate.

107 Energex, *6.02 – Model – SCS Opex Model* – 31 January 2024, *Energex, 2025–30 Regulatory Proposal*, 31 January 2024, p. 135.

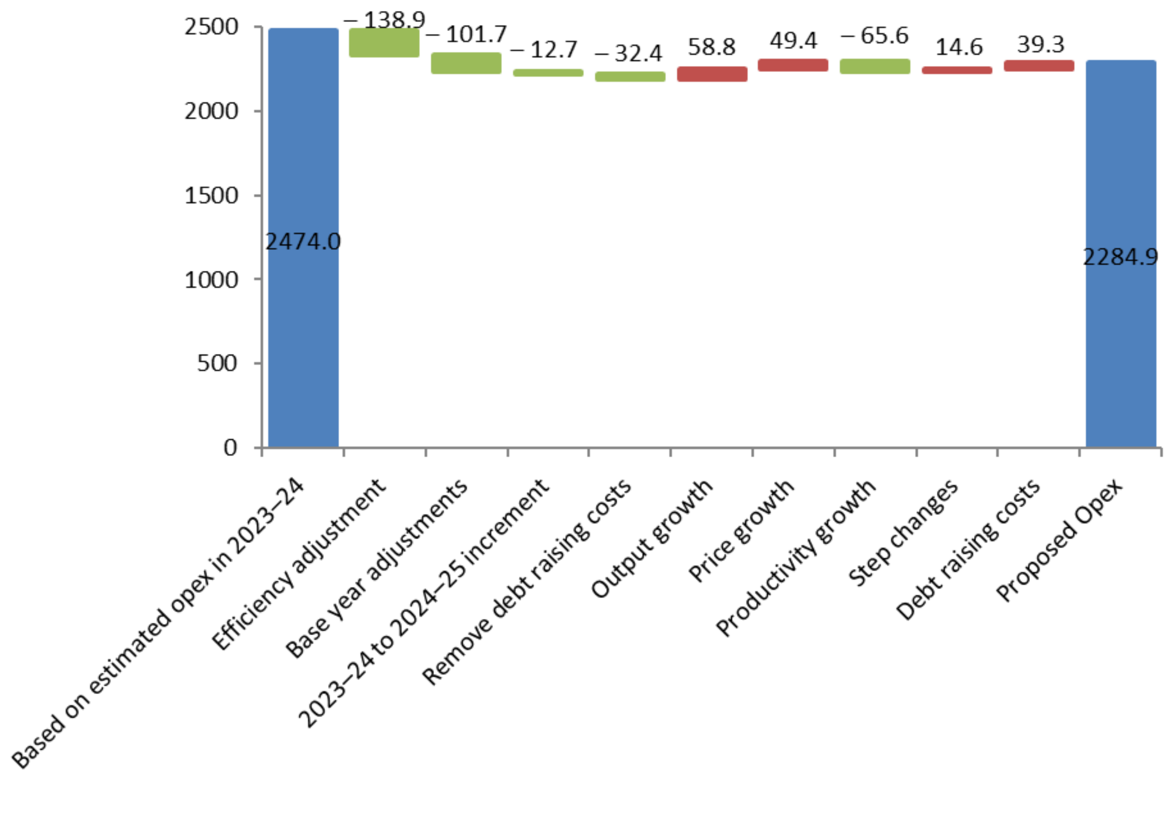
108 Energex, *6.02 – Model – SCS Opex Model* – 31 January 2024.

109 Energex, *2025–30 Regulatory Proposal* – 31 January 2024, p 130.

- applied a rate of change comprised of:
  - forecast **output growth** – averaging 0.9% per year ($58.8 million ($2024–25)), based on the output measure forecasts and weights from in our 2023 Annual Benchmarking Report,[110] consistent with our standard approach.
  - forecast input **price growth** – averaging 0.7% per year ($49.4 million (2024–25)), based on our standard approach of using a weighted average of forecast labour price growth and zero non-labour price growth.
  - forecast **productivity growth** of 1.0% per year (-$65.6 million ($2024–25)). This is higher than our 0.5% per year standard productivity growth forecast.[111]
- added one step change of $14.6 million ($2024–25) (or 0.6% of total forecast opex) to acquire, process and use smart meter data to increase visibility on its network and improve safety and reliability, integrate more renewables and reduce asset replacement costs.[112]
- added $39.3 million ($2024–25) for debt raising costs.

Figure 16 shows how each of these components contributes to Energex's total opex forecast.

Figure 16: Breakdown of Energex's opex forecast ($million, $2024–25)



Source: Energex, *6.02 – Model – SCS Opex* Model, 31 January 2024; AER analysis.

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110 Energex, *2025–30 Regulatory Proposal* – 31 January 2024, p. 139.

111 The output, price and productivity growth dollar amounts used here differ slightly from Energex's regulatory proposal because of a mechanical difference in calculating these trend components.

112 Energex, *2025–30 Regulatory Proposal* – 31 January 2024, p. 137.

Questions on forecast operational expenditure

9) Do you consider Ergon and Energex's opex forecasts for the 2025–30 regulatory control period reasonably reflect the efficient costs of a prudent operator?

10) Do you consider Ergon and Energex's proposed responses to affordability concerns expressed by stakeholders are appropriate and achievable?

11) Do you consider Ergon and Energex's proposals were sufficiently considered as a part of the stakeholder engagement processes, and adequately address the themes and issues raised by stakeholders?

4.5 Revenue adjustments under AER incentive schemes

Our calculation of total revenue for Ergon and Energex for the 2025–30 period will include adjustments for incentive schemes that applied in its determination for the current, 2020–25 period.

As set out in the proposals, these would include:

- A revenue reduction under the CESS, to provide a fair sharing of capex spent in excess of our approved forecast for 2020–25 between Ergon, Energex and their customers. For Ergon the proposed decrement to 2025–30 revenue is $625.9 million ($2024–25). For Energex it is $64.3 million ($2024–25).
- A revenue reduction under the Efficiency Benefit Sharing Scheme (EBSS), to provide a fair sharing of efficiency losses derived from spending more than approved forecast opex in the 2020–25 regulatory control period between Ergon, Energex and their customers. Ergon and Energex stated that their opex requirements increased in the current regulatory control period, resulting in both networks forecasting to overspend relative to the AER's opex forecasts. For Ergon the proposed reduction to revenue in the 2025–30 regulatory control period is $199.0 million ($2024–25). For Energex it is $121.8 million ($2024–25).[113]

The total revenue approved in our decisions will also include an allowance added for the DMIAM. Ergon and Energex have each proposed an allowance equivalent to $0.2m base allowance plus 0.075% of their total revenue to fund research and development into further, innovative demand management projects that have the potential to reduce long term network costs. This equates to $7.8 million for Ergon and $7.5 million for Energex ($2024–25). Any unspent portion of this allowance will be returned to customers in the next, 2030–35 period.[114]

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113 Ergon, *2025–30 Regulatory Proposal* – 31 January 2024, p. 149; *Energex*, *2025–30 Regulatory Proposal* – 31 January 2024, p.148.

114 AER - Demand management innovation allowance mechanism for electricity distribution network service providers - December 2017, clause 2.5(c); AER - Explanatory Statement - Demand Management Innovation Allowance Mechanism - December 2017, p. 31.

4.6 Corporate income tax

Our determination of regulated revenue must include an allowance for Ergon and Energex to recover the costs associated with the estimated corporate income tax payable during the 2025–30 period. We forecast the cost of corporate income tax in accordance with the requirements of the NER.[115]Using the approach set out in the PTRM, Ergon and Energex proposed forecast corporate income tax amounts of $4.0 million and $101.0 million ($2024–25) respectively for the 2025–30 period. We note that Ergon and Energex Energy have:

- Proposed forecasts for immediate expensing of capex for the 2025–30 period of $1,313.8 million and $837.2 million respectively, consistent with their current tax policy. The proposed amounts reflect Ergon and Energex's forecast capitalised overheads.[116]
- Adopted the diminishing value method for tax depreciation to all forecast capex, except for a limited number of assets which must be depreciated using the straight-line depreciation method under the tax law.

We will assess the appropriateness of the proposed amounts of immediate expensing and capex allocated for straight-line depreciation, based on the approach we have taken in recent revenue determinations.

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115 NER, cl. 6.5.3.

116 Energex, *Energex - 2025-30 Regulatory Proposal* – 31 January 2024, p. 165; Ergon Energy, *Ergon - 2025-30 Regulatory Proposal* – 31 January 2024, p. 165.

5 Incentive schemes to apply in 2025–30

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. They provide important balancing incentives under network determinations, encouraging businesses to pursue expenditures efficiencies while maintaining the reliability and overall performance of its network. Our final Framework and Approach (F&A) for Ergon and Energex noted our intention to apply the five incentive schemes and allowances in the 2025–30 regulatory control period that are set out below.[117] Ergon and Energex agreed with this approach in its 2025–30 proposals.[118] We will decide if, and how we will apply the schemes as part of our determinations, considering the information submitted.

- **Efficiency benefit sharing scheme (EBSS):**[119] provides Ergon and Energex with a continuous incentive to pursue efficiency improvements in opex and provide for a fair sharing of these between Ergon and Energex and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods.

  Ergon and Energex proposed to continue to apply the EBSS in the 2025–30 regulatory control period, subject to the following adjustments:[120]

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

- **Capital expenditure sharing scheme (CESS)**[121]. This incentivises efficient capex throughout the period, by providing incentives to improve efficiency by rewarding networks when expenditure lower than forecast and penalising them when expenditure is higher than forecast. Following a review in 2023, the version of the CESS that will apply to Ergon and Energex in 2025–30 reduces the rewards when a network business outperforms against its approved forecast by more than 10% but maintains the same penalties for underperformance.[122] This means that that in future periods the penalties to networks for overspending could be higher than the rewards for underspending. This asymmetry will reduce the costs of the CESS to consumers while maintaining strong incentives for efficiency.[123]

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117 AER, *Final Framework and approach Ergon Energy and Energex*, July 2025, pages 16-17.

118 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, pp. 148–149; Energex*, 2025–30 Regulatory Proposal* – 31 January 2024, pp. 147–148.

119 AER, *Efficiency benefit sharing scheme (Version 2)*, November 2013.

120 Ergon*, 2025–30 Regulatory Proposal* – 31 January 2024, p. 149; Energex, *2025–30 Regulatory Proposal* – 31 January 2024, p. 148.

121 *AER - Capital expenditure incentive guideline for electricity network service providers (Version 2) - April 2023*, p. 15.

122 AER – *Final decision – Capital expenditure incentive guideline* – April 2023

123 AER - Final decision - Review of incentive schemes for networks - April 2023

The CESS applies to both Ergon and Energex for the 2020–25 period. Ergon and Energex forecast a capex overspend of $2,056.9 million 357.3 million ($2024–25) and $357.3 million respectively for the 2020–25 period. This results in proposed CESS penalties totalling $48.3 million and $714.4 million for the 2020–25 regulatory control period. Ergon and Energex have not proposed any deferral of capex in its CESS calculations.

Exclusions to the CESS have been proposed for both businesses for capex during the ex-post period of 2018–19 to 2022–23. Ergon and Energex proposed to self–fund their ICT overspend from 2020–21 to 2022–23.[124]

Ergon also overspent by 43% in the ex-post period (the 2018–23 period). Our assessment for the overspend in the ex-post period will be consistent with the process outlined in the CESS Guideline.[125]

- **Demand management incentive scheme (DMIS)**[126] and demand management innovation allowance mechanism (DMIAM)[127]. The DMIS provides network businesses with financial incentives for undertaking efficient demand management activities as an alternative to more expensive capital investment in their networks, the costs of which have longer term impacts on consumers. The DMIAM funds research and development into further, innovative demand management projects that have the potential to reduce long term network costs.

Both Ergon and Energex support the Framework and Approach position to continue to apply the DMIS and DMIAM in the 2025 to 2030 regulatory control period.

Ergon and Energex expect to use DMIAM funding to explore opportunities associated with customer energy resources and facilitating the evolvement of capabilities and services required to transition to a smart grid.

- **Service target performance incentive scheme (STPIS)**[128]. The STPIS provides incentives for network businesses to maintain and improve network reliability and customer service performance, to the extent that consumers are willing to pay for such improvements. The STPIS is acts as a balance to our expenditure incentive schemes, ensuring businesses focus on genuine efficiency gains and do not compromise service levels when reducing expenditure.

In our July 2023 Framework and Approach paper we stated our intention to apply version 2.0 of the STPIS, noting that:

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124 Ergon, *2025–30 Regulatory Proposal* – 31 January 2024, p.148. and *Energex, 2025–30 Regulatory Proposal* – 31 January 2024, p.147.

125 AER - Capital expenditure incentive guideline for electricity network service providers (Version 2) - April 2023, p. 13.

126 AER - Demand management incentive scheme for electricity distribution network service providers - December 2017

127 AER - Demand management innovation allowance mechanism for electricity distribution network service providers - December 2017

128 AER - Service target performance incentive scheme for electricity distribution network service providers (Version 2) - November 2018

- The GSL component of the STPIS will not apply if Ergon and Energex remain subject to a jurisdictional GSL scheme
- The Customer Service (telephone answering) component of STPIS will not apply if Ergon and Energex propose, and we accept, a CSIS for the 2025–30 period.

We also proposed to apply a revenue at risk of ±2 % under the STPIS in 2025–30 as Ergon Energy and Energex had continued to demonstrate strong reliability performance in the current regulatory period. We considered the current revenue at risk to be a good balance between incentives to maintain reliability and consumer price impacts.

Ergon and Energex put forward identical positions in their proposals in relation to the STPIS. Both businesses support the F&A position to continue to apply version 2.0 of the STPIS in the 2025–30 regulatory control period.

In addition, Ergon and Energex proposed to continue with the current (2020–25 regulatory control period) arrangements (including being subject to the Queensland jurisdictional GSL scheme rather than applying the GSL component of the STPIS), but with two related exceptions.

The businesses propose that the customer service component of the STPIS (telephone answering) should not apply. As a result, they also propose that the overall revenue at risk cap be reduced to 1.8 per cent, down from the current 2 per cent. This is because a 0.2 per cent revenue at risk cap currently applies to the customer service component.

Ergon and Energex explained in their proposals that the proposed removal of the telephone answering parameter of the customer service component is an outcome of their customer engagement in developing their proposals. The feedback from engagement was that the businesses should not be incentivised for good customer service.

They also proposed to not apply a Customer service incentive scheme (CSIS) in their upcoming regulatory control period. Similar to views expressed on the telephone answering parameter, customers also indicated their opposition to the application of the CSIS to the two businesses.

Clause 5.1(b) of the STPIS states that the telephone answering parameter will apply during a regulatory control period except where the AER determines otherwise in its distribution determination.

We note that the CSIS is designed to offer an alternative to the (telephone answering) customer service component of the STPIS. However, it was not envisaged that neither scheme would apply. If neither scheme applies, then it may be astute to track a range of metrics over the period to improve transparency. This may set the scene for reconsideration of a CSIS at the subsequent reset for Ergon and Energex. We seek stakeholder feedback on what metrics could be tracked.

The proposed continued application of these schemes in 2025–30 is consistent with our own proposed approach for that period, which we set out in our Framework and Approach paper for these determinations in July 2023.[129]

Questions on incentive schemes

12) Do stakeholders agree with Ergon and Energex's proposal to not apply the CSIS?
13) Given Ergon and Energex did not propose to apply the CSIS, should the AER require them to apply the STPIS telephone answering parameter?
14) If the telephone answering parameter does not apply to Ergon and Energex, is it appropriate to reduce the revenue at risk cap to 1.8% of total revenue?
15) If Ergon and Energex do not apply a customer service scheme, what metrics should the AER track, if any, to ensure transparency?
16) Do you have any views on the proposed application of any of the above incentive mechanisms?

129 AER - Final Framework and Approach - Ergon and Energex 2025-30 - July 2023, p. 15.

6 Network pricing

Our determination for Ergon and Energex divides the regulated services they provide into different classifications, which determines how they will recover the cost of providing those services through network prices:

- Standard control services are those that can only be provided by the relevant distributor, and are common to most, if not all, of a distributor's customers. The costs of providing these services are captured in the building block revenue determination we've discussed in the previous sections of this paper and shared between all customers.
- Alternative control services are those that can only be provided by the relevant distributor but will only be required by some of its customers, some of the time; or services that can be purchased from the relevant distributor, but which can also—or have the potential to be—purchased from a competing provider. The cost of providing alternative control services is recovered from users of those services only.

We set out our proposed approach to the classification of distribution services to be provided by Ergon and Energex in 2025–30 in our Framework and Approach paper in June 2023.[130] Our determinations must apply these unless we consider a material change in circumstances justifies departure from them.[131]

Ergon and Energex proposed to retain the service classification approach set out in our Framework and Approach paper, except for type 5 and type 6 (legacy) metering. Ergon and Energex proposed to classify legacy metering as standard control rather than as alternative control. Legacy metering is currently classified alternative control.

While Ergon and Energex's proposal to reclassify legacy metering is a change from both the current classification and our Framework and Approach, we consider it is reasonable. In our Framework and Approach we noted the Australian Energy Market Commission's review of the regulatory framework for metering services, and our draft determinations for distributors in NSW, ACT, Tasmania and Northern Territory, will constitute a material change in circumstances. We consider reclassifying legacy metering services as standard control services is appropriate.

6.1 Control mechanisms for standard and alternative control services

A distribution determination must impose controls over the prices and/or revenues of direct control services.[132] The form and formulae of the control mechanisms in our distribution determination must be as set out in our Framework and Approach Paper for Ergon and Energex, which we published in June 2023.[133] There are only limited circumstances in which

130 *AER – Final Framework and Approach – Ergon and Energex 2025-30 – June 2023*, Appendix A.

131 NER, cl. 6.12.3(b)

132 NER, cl. 6.2.5(a)

133 *AER – Final Framework and Approach – Ergon and Energex 2025-30 – June 2023*, section 3.

our distribution determination can depart from the decision we made in the Framework and Approach Paper regarding control mechanisms.[134]

For the 2025–30 regulatory control period, that decision was to apply the same control mechanisms as we applied in the current, 2020–25 period:[135]

- A revenue cap for standard control services
- A price cap for alternative control services.

We made only minor changes to the formulae that support these, to reflect updates to incentive schemes since our last determination.[136]

Ergon and Energex adopted this approach in their proposals.

We consider these controls will continue to be appropriate in the 2025–30 regulatory control period.[137] In our consultation on the Framework and Approach paper we did not receive any submissions suggesting we depart from them.

6.2 Tariff structure statement

As part of their proposals, distributors are required to submit a tariff structure statement (TSS) to the AER.138 The TSS will apply for the 5-year regulatory control period. A TSS must set out a distributor's:

- proposed network tariffs
- network tariff structures
- charging parameters
- policies and procedures the distributor will use to assign customers to network tariffs or reassign customers from one network tariff to another.

The tariff structures provide the charging framework through which distributors collect their annual allowed revenue. Once approved, a TSS becomes a compliance document against which the AER assesses the distributor’s annual pricing proposals.

TSSs are also how distributors progressively reform their network tariffs for standard control services to better signal to customers the cost of providing network services. As customers ultimately pay for upgrades to network services, tariff reform that encourages more efficient use of the network will lead to lower network costs for all customers.

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[134] NER, cll. 6.12.3(c)(1) and (2); 6.12.3(c1).

[135] AER, Final decision – Energex distribution determination 2020-25 – Attachment 13 – Control mechanisms, November 2021; AER, Final decision – Ergon Energy distribution determination 2020-25 – Attachment 13 – Control mechanisms, November 2021

[136] *AER – Final Framework and Approach – Ergon and Energex 2025-30 – June 2023*, section 3.1.

[137] NER, cl. 6.2.5.

[138] This requirement came out of the AEMC 2014 rule change for distribution pricing.

We note that network tariffs are targeted at retailers who package them with other costs, such as the cost of wholesale energy, in their service offerings to electricity customers. As such, the retail electricity tariff may not directly reflect the network tariff.

This is the third regulatory period for which Ergon and Energex have submitted a TSS and it continues the process of incremental tariff reform.

Based on our initial review we consider Ergon and Energex have provided TSSs that partially meet our expectations. They also significantly reduced the number of tariffs offered which will make their future TSSs easier for stakeholders to engage with.

Questions on Tariff structure statements

17) Do you consider there are any aspects of Ergon or Energex's proposed TSSs that require adjustment?

18) Do time-of-use (TOU) - demand and energy tariffs as the default tariff structure for residential and small business customers balance the pace of reform with customer views/impacts?

6.2.1 Expectations for tariff structure statements

The Handbook sets out our expectations that a proposed TSS will:

- Demonstrate progression of tariff reform consistent with the network pricing objective and pricing principles set out in the Electricity Rules
  - Ergon and Energex proposed to progress tariff reform with more mature price signals, new charging parameters that reflect new periods of minimum network demand, and new two-way tariffs.
- Demonstrate incorporation of its tariff strategy in its overall business plan
  - Ergon and Energex's overviews draw high level links between their TSS and broader proposal. However, they did not clearly explain the interactions between tariffs and dynamic (export) connections, their connections policies and the Queensland Electricity Connections Manual (QECM).
- Demonstrate significant stakeholder engagement and broad stakeholder support
  - Ergon and Energex demonstrated mixed performance against this expectation. Meaningful stakeholder engagement started late in their TSS development process and the scope of issues open for stakeholder input was limited.
- Demonstrate insight into and management of any adverse customer impacts
  - Ergon and Energex modelling demonstrated impacts would be mixed, with average bill decreases of 2% to 4% in 2025 for residential customers moving from flat tariffs to the default (TOU) - demand tariffs [139;140] but average bill increases of 8% to 13% for residential customers on the default smart meter tariff (which will change from

139 Energex 9.02 – *Network Bill Impacts,* 31 January 2024, p 14.

140 Ergon 9.02 – *Network Bill Impacts*, 31 January 2024, p 16

transitional demand to TOU demand and energy and will include time of use energy windows, noting the energy charges are currently flat.)[141, 142, 143]

- Ergon and Energex proposed to manage adverse impacts through a 12-month reassignment lag for customers with replacement meters, by reducing some fixed charges, and by providing alternative opt-in TOU tariffs. It is unclear how they will manage first year sharp (averaging up to 13%) residential bill impacts.

6.2.2 Progress on tariff reform

Energex's and Ergon's proposed tariff reforms focus on providing increasingly cost reflective tariffs and restructured default tariffs for standard asset customers (SAC). Energex refined its default connection asset customers (CAC) tariffs[144] and Ergon introduced a new default tariff for CAC. Further key reforms include[145]:

- streamlining available tariffs by withdrawing closed and little used tariffs
  - Energex: 3 SAC residential, 3 SAC small business, 2 SAC large business, 2 CAC
  - Ergon: 2 SAC residential, 4 SAC small business, 3 SAC large business, 3 CAC
- strengthening the price signals of residential and small business default tariffs
- adjusting tariff charging windows to reflect changing demand profiles, including introducing solar soak periods to default demand TOU tariffs
- withdrawing their transitional demand tariffs, and instead introducing a 12-month lag before customers are assigned to their fully cost reflective default tariffs
- introducing secondary export reward tariffs (residential and business (SAC))
- introducing storage tariffs (for storage with above 30kW export capacity)
- introducing new (secondary) load control tariffs and dynamic (export) connections
- proposing four contingent adjustments to key tariff parameters or assignment policies.

We consider the incorporation of a contingent adjustment to tariff parameters is, when well defined and its trigger is made clear, a reasonable way of balancing certainty and flexibility.

6.2.3 Maturing of price signals and default tariff

Ergon and Energex proposed to replace their existing default tariffs for residential and small business customers with new TOU demand and energy tariffs. The existing transitional tariffs are TOU-demand, but have flat charges, designed to allow customers gain familiarity with demand and TOU tariff structures.

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141 Energex 9.02 – *Network Bill Impacts*, 31 January 2024, p 10.

142 Ergon 9.02, – *Network Bill Impacts*, 31 January 2024, p 10.

143 Ergon and Energex's modelling shows sharper bill impacts in the first year (2025) because of changes to default tariff structures and expects the impact to plateau from 2026.

144 Ergon has not proposed changes to the structure of its default CAC tariffs. For Energex's CAC customers, site-specific fixed charges will be removed from the default tariffs (for Energex - 11kV Bus demand and 11kV TOU Demand)

145 *Energex Tariff Structure Statement Compliance Statement January 2024 – public* and *Ergon Tariff Structure Statement Compliance Statement January 2024 – public*

Ergon and Energex proposed to:

- progressively increase the peak demand charges over the 2025–30 period to gradually achieve fully cost reflective tariffs [146]
- set distribution charges in solar soak periods to zero
- remove the volume charges that (in the existing transitional tariff) apply jointly with demand charges during the peak demand window
- offer additional optional demand tariffs from 2027 and (long- term) withdraw TOU only tariffs from 2030.[147]

We note that Ergon and Energex have long-term plans to move to demand or capacity charges only, and to no longer offer energy-based tariffs. This is not an issue we must decide on during this tariff structure statement determination, but we are interested in stakeholder view on these plans.

6.2.4 Export reward tariffs

Ergon and Energex proposed to introduce two-way pricing (providing rewards and charges for customers who export electricity to the grid) as allowed for under the AEMC's Access, pricing and incentive arrangements for distributed energy resources rule change.[148] Both networks included relevant customer protections as required by the NER, including:

- a basic export level (the amount of electricity a customer may export at no cost)
- an export tariff transition strategy.

Ergon and Energex proposed export reward tariffs for residential, and small and large business SAC, where a customer's export capacity is below 30kW. From July 2026 the tariffs would be mandatory for new customers and opt-in for existing customers. The tariffs would also become mandatory for existing customers from July 2028, providing Ergon and Energex are able to offer dynamic connection arrangements by then. Once dynamic connection arrangements are available, customers would be able to opt-out of the mandatory assignment if the customer instead enters a dynamic connection arrangement.[149]

Ergon and Energex modelling shows the impact of two-way tariffs on residential customers differs depending on the size of a customer's inverter, location of solar panels and the extent to which customers self-consume energy. Customers will face an average annual bill impact of between -\$0.4 to \$77.3 (Ergon) and \$-1.2 to \$20.4 (Energex).[150] Ergon and Energex did not show similar modelling for business SAC.

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146 Energex, *Tariff Structure Statement – Explanatory Statement*, January 2024, p 53; Ergon, *Tariff Structure Statement – Explanatory Statement*, January 2024, p 55.

147 Energex, *Tariff Structure Statement – Explanatory Statement*, January 2024 p 55.

148 In 2021 the AEMC made a new rule change, Access, pricing and incentive arrangements for distributed energy resources, to integrate distributed energy resources more efficiently into grid and allow two-way pricing.

149 See section below for an explanation of dynamic connections.

150 Ergon, *Attachment 9.02 – 2025-30 Network bill impacts* – January 2024 – public, 18; Energex, *Attachment 9.02 – 2025-30 Network bill impacts*, January 2024, p 17.

Two-way pricing is a new feature for TSSs so we intend to closely examine Energex's and Ergon's two-way tariff proposal, as the AER is doing for the NSW and ACT resets currently underway.

6.2.5 Dynamic connections

Ergon and Energex proposed dynamic connection arrangements for exporting customers. A dynamic connection would enable Energex or Ergon to set and vary export limits over time and location depending on the available capacity of the local network or power system as a whole. Exporting customers who agree to a dynamic connection could opt-out of the mandatory assignment to two-way tariffs when that would otherwise apply.

One of Energex's and Ergon's proposed storage tariffs (the Dynamic Flex Storage tariff) requires the customer to adopt a dynamic connection, in return for a rebate for up to 40 hours per year for exports. Ergon and Energex proposed to defer detail on how the rebate pricing mechanism will work to the annual pricing proposal process.

The dynamic connection approach is enabled by new connection standards that Ergon and Energex have introduced to their Queensland Electricity Connection Manual.[151] The cost of the dynamic connection, who pays for connection and whether the dynamic connection can then be unwound are not explained in the TSSs or their explanatory statements.

6.2.6 Electric vehicles (EVs)

Uptake of electric vehicles poses both opportunities and challenges for electricity networks. Ergon and Energex's TSSs include features that respond to this.

Their proposed two-way tariffs, among other things will encourage EV owners to charge EVs from their own solar.

Optional residential and small business demand tariffs to be introduced in 2027 are intended to incentivise customers/retailers to smooth demand even in shoulder periods and discourage high demand immediately after the peak window. This is particularly targeted at a growing number of behind the meter batteries and electric vehicles.

Relevant to EV public charging stations, Ergon and Energex apply a 100MWh (annual consumption) threshold to designate large businesses and apply demand charges. The 100MWh threshold aligns with the *National Energy Retail Law (Queensland) Act 2014*. Ergon and Energex acknowledged potential impacts for customers with energy use around the 100 MWh threshold and may apply a tolerance limit on tariff thresholds of 15% on an annualised consumption basis to mitigate frequent tariff re-assignment and customer impact.[152] Ergon and Energex also proposed to continue to offer their existing primary load control tariffs to EV charging station operators.

We note that application of the 100MWh threshold may prevent some EV charging stations from opting out of demand tariffs. We further note that Energex's and Ergon's approach is different to arrangements applicable in Victoria, NSW and the ACT, where EV charging

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151 Version 4 was released in December 2023 and came into force 21 February 2024.

152 *Energex Tariff Structure Statement Compliance Statement January 2024 – public* p 31 and *Ergon Tariff Structure Statement Compliance Statement January 2024 – public* p 31.

stations (and other business customers) may opt out of demand tariffs up to a 160 MWh threshold.

Ergon and Energex also proposed mandatory assignment of EV fast chargers to controlled load tariffs, discussed below.

6.2.7 Mandatory load control for EV customers with fast chargers

Through the Queensland Electricity Connection Manual, Ergon and Energex impose direct distributor control on any appliance greater than 20 Amps (including EV fast chargers).[153] Under this policy Ergon and Energex may switch off (or slow down) a customer's EV fast charger without notice. Minimum hours of supply are specified in the customer's network tariff. Customers are unable to override the external control.

A recent update to the Queensland Electricity Connection Manual included a new optional mechanism for load control whereby a load control device is installed in the customer's fuse box, adjacent to the customer's meter. Under the TSS proposals, a new load control tariff would be offered in combination with this new load control device.

Currently, customer fast chargers must be on an existing secondary load control tariff (the two available options allow Ergon and Energex to switch off supply for up to 6 hours and 16 hours respectively). Under the proposed approach, customers would have an additional load control tariff option and may charge their EV from their own rooftop solar. The new tariff (labelled by Ergon and Energex as their flexible load control tariff) would apply as a discount on the daily fixed charge of the customer's primary tariff and would allow Ergon and Energex to switch off supply for up to 6 hours. Customers who opt-in to the proposed flexible load control tariff could later opt-out but if they chose to do so they would incur an upfront cost to remove the load control device.

We seek stakeholder views on the appropriateness of distributor-lead load control to customers with EV fast chargers.

6.3 Alternative control services

Alternative control services are customer specific or customer requested services and so the full cost of the service is attributed to that particular customer, or group of customers, benefiting from the service. Our determinations set service specific prices to provide a reasonable opportunity to the distributor to recover the efficient cost of each service from customers using that service.

Our F&A classified the following as ACS:

- metering services
- ancillary network services, and
- public lighting services.

153 There are three forms of control available – dynamic control, basic active management (both introduced in the newest version of the QECM) and control via a load control tariff. All forms of control require a device to be installed.

6.4 Metering

Metering services include the maintenance, reading, data services and recovery of capital costs of meters. Since 2017 there has been competition for the provision of meters by retailers and/or other third parties, with smart meters now being the meters installed. However, Ergon and Energex are still responsible for providing metering services for the meters it historically installed (legacy meters).

In August 2023, the Australian Energy Market Commission (AEMC) published its Final Report on the 'Review of the Regulatory Framework for Metering Services' (AEMC final report) which set the objective to replace all distributor owned legacy meters with smart meters provided by other parties by 2030. To do this, the distributors are to schedule bulk meter replacements, largely on a geographical basis. Under this approach customers will have no choice as to when their meter will be replaced as it will be determined by the distributors and other providers.

Our assessment of the ACT, NSW and TAS distributors 2024–29 proposals identified an issue where customers whose meters are replaced later in the replacement program would incur inequitably higher costs for metering services than customers whose meters are replaced earlier. This arises because a large fixed-cost base (e.g., systems and IT, base labour force) will be recovered over a rapidly declining customer base. In addition, the per unit costs to read a meter increase as it is further to travel between each manually read meter.

Due to the accelerated retirement of legacy meters and potential for inequitable prices, we are interested in stakeholder's feedback on the aspects detailed below.

6.4.1 Change in service classification and form of control for metering services

In the Framework and Approach (F&A) for Ergon and Energex, we classified legacy metering services as ACS.[154] We expected Ergon and Energex's proposals to depart from their F&A, where necessary to reflect the AEMC Final Report.[155]

Our draft decisions for the ACT, NSW and TAS distributors noted the AEMC Final Report constituted a 'material change in circumstances' which would permit a change in classification from the F&A.[156] We consider a reclassification of legacy metering services as standard control services (SCS) and with costs recovered through the revenue cap is likely to be more appropriate in the revised proposals in order to reduce material price impacts for

[154] AER - *Final Framework and Approach - Ergon and Energex 2025-30* - July 2023, pp. 30-32.

[155] AER - *Final Framework and Approach - Ergon and Energex 2025-30* - July 2023, p. 6.

[156] See for example, AER, *Draft decision – Ausgrid 2024–29 – Attachment 20 – Metering services*, September 2023, p. 7.

customers through the metering transition. Contribution by all customers is appropriate as all energy users will recognise the network benefits of this transition.[157]

Following the draft decisions, we published guidance on a common approach or distributors intending on reclassifying metering services as SCS.

Ergon and Energex have subsequently departed from this approach and proposed to reclassify these services as SCS.[158] It also provided a revenue cap control mechanism consistent with the approach set out in our guidance note for metering services.

6.4.2 Cost recovery

In the 2020–25 period, the cost recovery of legacy meters involved separate capital and non-capital charges. These are charged to individual customers (user pays) and are regulated under a price cap.

Capital charges relate to the recovery of costs associated with installation and management of the legacy metering asset base. All customers who had a legacy meter prior to 30 June 2015 incur capital charges, regardless of whether they still have a legacy meter or not.[159] Non-capital charges relate to the recovery of costs associated with the operation of the remaining legacy meters and are charged to customers who still have either Energex or Ergon-owned legacy meters installed at their premises.[160]

As noted above, as legacy meters are replaced by smart meters, the per unit cost of operating and maintaining legacy meters increases. As more legacy meters are retired, customers with legacy meters could face material increases in their charges.[161]

Additionally, customers who have had smart meters installed will experience costs related to the smart meters, as well as ongoing capital costs related to their historical legacy meter.

Ergon and Energex proposed to implement the following settings to mitigate the inequitable price increases to individual customers by:

- recovering costs from all small low voltage customers, instead of a decreasing number of customers that still have legacy meters.
- recover costs through a combined price (inclusive of both capital and non-capital components), rather than the current approach of separate capital (charged to all customers that have historically had a distributor-owned legacy meter) and non-capital components (charged only to those that still have a legacy meter).
- smooth the cost recovery over the 2025–30 period.

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157 See for example, AER, *Draft decision – Ausgrid 2024–29 – Attachment 20 – Metering services*, September 2023, p. 3.

158 Ergon - *2025-30 Regulatory Proposal - 31 January 2024, p. 181;* Energex - *2025-30 Regulatory Proposal – 31 January 2024 – public, p. 180.*

159 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 181; Energex - *2025-30 Regulatory Proposal* – 31 January 2024 – public, p. 180.

160 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 181; Energex - *2025-30 Regulatory Proposal* – 31 January 2024 – public, p. 180.

161 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 182; Energex - *2025-30 Regulatory Proposal* - 31 January 2024 – public, p. 181.

Key considerations for our assessment of Ergon and Energex's proposals will be the price impacts for consumers and views put forward by stakeholders.

6.4.3 Operating expenditure and accelerated depreciation

Most of the legacy metering costs that Ergon intends to recover are operating expenditure (opex).[162] Most of the legacy metering costs that Energex intends to recover are depreciation costs and followed by operating expenditure (opex).[163] Both networks used a base-step-trend approach in forecasting opex taking into consideration real price growth and the forecast speed of the rollout. There are no step changes to reflect planned the transitional costs in the coming period including:[164]

- implementation and monitoring of its legacy meter retirement plan
- reduced costs for testing and inspection of legacy meters.

Ergon and Energex acknowledged that full smart meter deployment is the objective but are concerned there will be a small number of sites (estimated to be 15 per cent of their current meter population) that cannot be transitioned within the 2025–30 timeframe due to reasons such as switchboard constraints or access issues. They intend to seek an exemption.[165]

Our assessment of Ergon and Energex's proposals will examine the assumptions behind the base-step-approach and take into consideration stakeholder views on Ergon and Energex's opex forecasts.

Ergon and Energex have adopted our straight-line depreciation approach and accelerated the depreciation of its historical legacy metering asset base for the 2025–30 regulatory control period.[166] Ergon proposed to recover its metering asset base of $42.18 million in the 2025–30 regulatory control period.[167] Energex proposed to recover its metering asset base of $210.73 million in the 2025–30 period.[168]

We are interested in stakeholder views on whether accelerated depreciation of these asset bases is appropriate. The benefits of this include the avoided regulatory and administrative burden of the recovery of those asset bases in future regulatory control periods. We note that accelerated depreciation will increase costs in the short term. Increases may be accentuated by other expected short-term cost increases resulting from the increasing per-unit cost of operating expenditure, and any accelerated retirement of legacy meters.

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162 Ergon - *10.04 - Metering PTRM 2025-30* - January 2024 – public.

163 Energex - *10.04 - Metering PTRM 2025-30* - January 2024 – public.

164 Ergon - *2025-30 Regulatory Proposal* - January 2024 – public, p. 186; *Ergon - 10.02 - Metering expenditure model 2025-30* - January 2024 - public.xlsm; *Energex - 2025-30 Regulatory Proposal* - January 2024 – public, p. 184; *Energex - 10.02 - Metering Expenditure Model 2025-30* - January 2024 - public.xlsm.

165 Ergon - *2025-30 Regulatory Proposal* - 31 January 2024, p. 185; Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 184.

166 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 184-185; Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 182-183.

167 Ergon - *10.04 - Metering PTRM 2025-30* – 31 January 2024 – public.

168 Energex - *10.04 - Metering PTRM 2025-30* – 31 January 2024 – public.

6.4.4 Mount-Isa Cloncurry network

The AER is also responsible for the economic regulation of the Mount Isa-Cloncurry network. As the Mount Isa-Cloncurry network is not connected to the national grid, the AEMC metering reforms do not apply in the area. Despite this, Ergon proposed that metering services in the Mount-Isa Cloncurry network should be treated consistently with its grid-connected network and be reclassified as SCS. Ergon considers that treating the Mount Isa-Cloncurry network in the same way as the grid-connected network is consistent with previous AER decisions.

Ergon expects it to be administratively burdensome to treat the Mount Isa-Cloncurry network differently to the grid-connected network. Metering costs for the Mount Isa-Cloncurry network is immaterial relative to Ergon's overall metering costs. This area has approximately 1 per cent of Ergon's customers.

More importantly, Ergon considers that Mount Isa-Cloncurry metering services must be treated similarly to the grid-connected network due to the application of the Uniform tariff policy in Queensland. The Uniform tariff policy means that customers in the isolated networks will pay South East Queensland equivalent tariffs which will include Energex's legacy metering costs reclassified as SCS.[169]

Key considerations for our assessment of Ergon's proposal for the Mount Isa-Cloncurry network will be the price impacts for consumers and views put forward by stakeholders.

Questions on metering

19) Do you have any comments on the proposed cost recovery approach for legacy metering services?

20) Do you have any feedback about regulating the Mount Isa-Cloncurry network the same way as Ergon's grid-connected?

6.5 Ancillary network services

Ancillary network services are non-routine services provided to individual customers on request. These services are either charged on a fee or quotation basis. Fee-based services tend to be homogeneous in nature and can be costed in advance of supply with reasonable certainty. Quoted service prices are determined at the time of a customer's enquiry and reflect each customers' individual requirements.

Ancillary network services are regulated by price cap. Our distribution determination sets first year price caps for fee-based services, labour escalators used to escalate prices for the remaining years of the regulatory period, and capped labour rates used in quoted services.

Labour costs are a large proportion of ancillary network service costs. Another significant cost element is the time taken to perform the service, including travel time. Our assessment includes review of these elements for the most frequently requested ancillary network

[169] Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 183.

services. We also benchmark proposed labour rates and prices for fee-based services across distribution networks as well as with prices from the current regulatory period.

In March 2022, we published a standardised ancillary network services model for use by electricity distributors to develop their prices. This streamlines our assessment, increases consistency, and provides stakeholders greater scope to engage in our determinations.

5.6.1 Pre-lodgement engagement and service offerings

Ergon and Energex's stakeholder engagement consisted of presenting its proposed changes to its fee-based services at the Energy Retailer Forum held in October 2023. In response, the key concern raised by stakeholders was the removal of some after-hours services for ancillary services affecting customer incentives and future costs.[170] The key change Ergon and Energex proposed is to consolidate their fee-based services. This involved discontinuing the Anytime services, some After Hour services and amalgamating the two feeder type permutations (Urban/Short Rural and Long Rural/Isolated).[171]

Ergon and Energex also proposed to introduce the following fee-based services:[172]

- Remote De Energisation: this is to accommodate the changing work environment.
- Property Searches (including complex property searches): these are quoted services in the 2020-25 period.

These changes reduced Ergon's fee-based services from 310 to 137 services and Energex's fee-based services from 142 to 115 services.

5.6.2 Benchmarking labour rates

Labour rates are a key cost input for ancillary network service prices. The distributors' proposed labour rates are assessed against benchmark efficient maximum labour rates developed using a bottom-up cost build up across six categories (administration, field worker, technical specialist, engineer, senior engineer, and project manager).

The benchmark rates include increases to the superannuation allowance and the vehicle allowance because of the changes in the superannuation guarantee and inflation. The 'transmission line design engineer' has been removed from the engineer benchmark category as this occupation is not an appropriate benchmark for distributors' engineers.

Ergon and Energex proposed to apply different overhead rates to their fee-based and quoted labour rates. Ergon proposed to apply the weighted average overhead rate for their fee-based services to align with our standardised ancillary network services model.[173]

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170 Ergon - *2.03 - Customer and Stakeholder Engagement Summary report* - January 2024 – Public, p. 47 and Energex - *11.09 – ACS Explanatory Statement* - January 2024 - Public, p.34.

171 Ergon - *11.09 – ACS Explanatory Statement* - January 2024 – Public, p.32-33 and Energex - 11.09 – ACS Explanatory Statement - January 2024 - Public, p.33.

172 Ergon - *11.09 – ACS Explanatory Statement* – January 2024 – Public, p.34 and Energex - 11.09 – ACS Explanatory Statement - January 2024 - Public, p.34.

173 Ergon - *11.09 – ACS Explanatory Statement* - January 2024 – Public, p.35 and Energex - 11.09 – ACS Explanatory Statement - January 2024 - Public, p.34.

However, Ergon proposed to apply the unadjusted overhead rate as per its Cost Allocation Method for quoted services to effectively recover costs.[174]

Most of Ergon and Energex's proposed labour rates are lower than our preliminary maximum efficient benchmark rates (these are based on inputs which will be updated for our draft decision). However, Energex's proposed labour rates for quoted services are higher than our preliminary benchmark rates. Our draft decision on Ergon and Energex's labour rates will be dependent on the updated maximum efficient benchmark rates we determine after applying the most recent inputs.

5.6.3 Benchmarking fee-based services prices

Proposed fee-based services are also benchmarked against prices from the current regulatory control period as well as similar services supplied by other distributors. Cost inputs may also be benchmarked.

Ergon and Energex proposed large price increases to most fee-based services. Ergon and Energex stated the prices changes were driven by updated contractor rates, increasing crew size for jobs deemed high risk and updated service timings and travel times.[175]

Questions on ancillary network services

21) Do you consider the rationalisation of the fee-based services appropriate?

22) Do you consider that sufficient justification has been provided in the provision of new services?

23) Do you consider the proposed labour rates and fee-based prices to be reasonable?

6.6 Public lighting

Public lighting services include the provision, construction and maintenance of public lighting assets. Customers of public lighting services primarily are local government councils and jurisdictional main roads departments.

There are a number of different tariff classes and prices for public lights. The factors influencing prices for a particular installation include which party is responsible for capital provision, and which party is responsible for maintaining and/or replacing installations.

Ergon and Energex's prices recover costs of providing public lighting services (including capital and operating expenditure as appropriate).

For the 2025–30 period, Ergon and Energex used a building block model to generate revenues for public lighting services which was translated into tariffs using a pricing model.

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174 Ergon - *11.09 – ACS Explanatory Statement* - January 2024– Public, p.35-36 and Energex - *11.09 – ACS Explanatory Statement* - January 2024 - Public, p.35-36.

175 Ergon - *11.09 – ACS Explanatory Statement* - January 2024 – Public, p.32 and Energex - *11.09 – ACS Explanatory Statement* - January 2024 - Public, p.32-34.

For opex, important drivers include asset failures rates, spot and bulk maintenance cycles, labour rates and traffic controller assumptions. For capex, the price of materials is the underlying driver. Corporate overheads are also a material driver of public lighting prices.

6.6.1 Pre-lodgement engagement

Because of the specific nature of public lighting services and the relatively small number of public lighting customers, Ergon and Energex held bespoke engagement for public lighting.

The public lighting consultation was in stages. Starting in November 2022, the initial 'Inform' stage aimed to build customer understanding. This included sessions on areas such as the proposal process and the revenue and tariff setting process.[176]

Consultation then transitioned to more interaction and engagement with customers and stakeholders. Ergon and Energex stated they held individual and group sessions to provide customers and stakeholders the opportunity to influence their strategy. Ergon and Energex also published six fact sheets on topics such as the regulatory determination process, how they derive public lighting revenue and prices, and the introduction of smart cells.[177]

In July 2023, Ergon and Energex published Issues Papers seeking feedback on five areas:[178]

- the pace of the LED rollout for the 2025–30 period
- proposed changes to the suite of public lighting tariffs
- managing customer impact for the recovery of the residual value of conventional lights
- funding of the conversion of the gifted assets to LED, and
- options for the deployment of smart cells.

Ergon and Energex reflected customer responses in their Draft Plan, published in September 2023, and sought further feedback.[179]

6.6.2 Service and price offerings

Ergon and Energex proposed to keep their rate 1[180] and rate 2[181] tariffs unchanged from the 2020–25 period, consistent with customer feedback during pre-lodgement engagement.[182]

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176 Ergon - *2025-30 Regulatory Proposal* - 31 January 2024, p. 190. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 189.

177 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 190. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 189.

178 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 191. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 190.

179 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 191. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 190.

180 Rate 1 tariffs recover the capital and operating costs of non-gifted assets. There are four rate 1 tariffs reflecting combinations of major vs minor roads, and conventional vs LED lights.

181 Rate 2 tariffs recover operating costs of assets gifted to Ergon/Energex. There are four rate 2 tariffs reflecting combinations of major vs minor roads, and conventional vs LED lights.

182 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 192. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 191.

Ergon and Energex also decided to retire their rate 4[183] tariffs, which had limited uptake during the 2020–25 period and proposed two new tariffs:[184]

- Rate 2A[185] to reflect Ergon and Energex funding the capital costs to convert rate 2 conventional assets to LED assets - this tariff will recover capex and opex charges through the public lighting charges, and
- Rate 2B to reflect the introduction of smart control devices - this tariff recovers the cost of the Data Management System, user interface, set up digital costs and costs associated with replacing defective assets.

Ergon and Energex proposed to reassign rate 4 assets to a rate 2 LED tariff on 1 July 2025, and customers will no longer be charged the residual value of the non-gifted infrastructure.

The ACS price schedules contain Ergon's[186] and Energex's[187] proposed suite of public lighting services and prices for the 2025–30 period.

Ergon's[188] and Energex's[189] proposals describe how they developed their proposed public lighting prices including their engagement process and the principal drivers of the proposed prices. Ergon's[190] and Energex's[191] proposals also included the building block models they used to derive their forecast revenues for providing public lighting services as well as the models that convert these revenues into prices.

Ergon and Energex noted the average price impact is an 18% increase in the first year of the 2025–30 period followed by an average 1% annual decrease for the remaining four years.[192]

Taking into account stakeholder feedback, Ergon and Energex also proposed to introduce smart lighting technologies and associated prices on an as-requested basis.[193]

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183 Rate 4 tariffs are for assets where customers fund the replacement of the rate 1 luminaire and lamp to LED, but where the associated pole and cabling are legacy and non-gifted assets. There are two rate 4 tariffs (major vs minor roads).

184 Ergon - 2025-30 Regulatory Proposal – 31 January 2024, p. 192. Energex - *2025-30 Regulatory Proposal* - January 2024, p. 191.

185 There are two rate 4 tariffs (major vs minor roads).

186 Ergon - *1108 - ACS Price schedule 2025-30* - January 2024 – public, 'Public Lighting Services'.

187 Energex - *1108 - ACS price schedule 2025-30* - January 2024, 'Public Lighting Services'.

188 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 190–197; Ergon - *11.09 - ACS* Explanatory Statement - January 2024 – public, pp. 5–30.

189 Energex - *2025-30 Regulatory Proposal* – 31 January 2024 - public, p. 189-196. Energex - *11.09 - ACS Explanatory Statement* - January 2024 – public, pp. 5–30.

190 Ergon - *11.01 - ACS Public lighting capex and opex forecasting model 2025-30* - January 2024; Ergon - *11.02 - ACS Public lighting pricing model* - January 2024 – public; *Ergon - 11.03 - ACS Public Lighting RFM 2025-30* - January 2024; *Ergon - 11.04 - ACS Public lighting PTRM 2025-30* - January 2024.

191 Energex - *11.01 - ACS Public lighting capex and opex forecasting model 2025-30* - January 2024; Energex - *11.02 - ACS Public lighting pricing model* - January 2024; Energex - *11.03 - ACS Public lighting RFM 2025-*30 - January 2024; Energex - *11.04 - ACS Public lighting PTRM 2025-30* - January 2024.

192 Ergon - *11.09 - ACS Explanatory Statement* - January 2024 – public, p. 26; Energex - *11.09 - ACS Explanatory Statement* - January 2024 – public, p. 26.

193 Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, pp. 193–194; Energex – *2025-30 Regulatory Proposal* – 31 January 2024, pp. 192–193.

Ergon and Energex developed prices for smart controls using cost build-up models.[194]

6.6.3 LED and other new technologies

During pre-lodgement engagement, Ergon and Energex asked stakeholders whether they prefer a moderate deployment or an accelerated deployment of LED technology. In the former, Ergon and Energex would aim to convert 65% of its public lights to LED by 2030. In the latter, Ergon and Energex would aim for 100% conversion.[195]

Ergon and Energex stated all respondents to its consultation documents endorsed 100% conversion by 2030. Ergon and Energex therefore aim to convert all of their conventional public lights to LED technology in the 2025–30 period due to improved reliability and efficiency and reduced environmental impact.[196]

To manage customer impact, Ergon and Energex will extend recovery of the residual value of conventional assets beyond 2030. Ergon and Energex stated customers unanimously supported this approach was during their pre-lodgement engagement.[197]

Questions on public lighting

24) Do you consider Ergon and Energex's public lighting proposal generally incorporates stakeholder inputs from this pre-lodgement engagement? If not, did Ergon and Energex communicate these potential departure points to stakeholders and provide adequate explanation during pre-lodgement engagement?

25) Do you support Ergon and Energex's proposed suite of public lighting services and prices?

26) Do you have any other comments on Ergon and Energex's public lighting proposal and their pre-lodgement engagement?

[194] Ergon - *11.05 - ACS Smart control pricing model* - January 2024; Energex - *11.05 - ACS Smart control pricing model* - January 2024.

[195] Ergon - *11.09 - ACS Explanatory Statement* - January 2024 – public, p. 10; Energex - *11.09 - ACS Explanatory Statement* - January 2024 – public, p. 10.

[196] Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 190. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 189.

[197] Ergon - *2025-30 Regulatory Proposal* – 31 January 2024, p. 192. Energex - *2025-30 Regulatory Proposal* – 31 January 2024, p. 191.

7 Summary of questions

Consumer engagement

1) Do Ergon and Energex's proposals adequately reflect consumers' affordability concerns?
2) Have Ergon and Energex chosen the right topics to engage with consumers on?
3) To what extent do you consider consumers were able to influence the topics Ergon and Energex engaged on?
4) Are there topics that you would have preferred to consider in greater detail? Please give examples.

Capital expenditure

5) Do you consider the AER's proposed approach to the ex-post review of Ergon's capex overspend is appropriate?
6) Do you consider Ergon and Energex's capex forecasts for the 2025–30 regulatory control period reasonably reflect the efficient costs of a prudent operator?
7) Do you consider Ergon and Energex's proposed responses to affordability concerns expressed by stakeholders are appropriate and achievable?
8) Do you consider Ergon and Energex's proposals were sufficiently considered as a part of the stakeholder engagement processes, and adequately address the themes and issues raised by stakeholders?

Operational expenditure

9) Do you consider Ergon and Energex's opex forecasts for the 2025–30 regulatory control period reasonably reflect the efficient costs of a prudent operator?
10) Do you consider Ergon and Energex's proposed responses to affordability concerns expressed by stakeholders are appropriate and achievable?
11) Do you consider Ergon and Energex's proposals were sufficiently considered as a part of the stakeholder engagement processes, and adequately address the themes and issues raised by stakeholders?

Incentive schemes

12) Do stakeholders agree with Ergon and Energex's proposal to not apply the CSIS?
13) Given Ergon and Energex did not propose to apply the CSIS, should the AER require them to apply the STPIS telephone answering parameter?
14) If the telephone answering parameter does not apply to Ergon and Energex, is it appropriate to reduce the revenue at risk cap to 1.8% of total revenue?
15) If Ergon and Energex do not apply a customer service scheme, what metrics should the AER track, if any, to ensure transparency?
16) Do you have any views on the proposed application of any of the above incentive mechanisms?

Questions on Tariff structure statements

17) Do you consider there are any aspects of Ergon or Energex's proposed TSSs that require adjustment? 18) Do time-of-use (TOU) - demand and energy tariffs as the default tariff structure for residential and small business customers balance the pace of reform with customer views/impacts?
Questions on metering 19) Do you have any comments on the proposed cost recovery approach for legacy metering services? 20) Do you have any feedback about regulating the Mount Isa-Cloncurry network the same way as Ergon's grid-connected?
Questions on ancillary network services 21) Do you consider the rationalisation of the fee-based services appropriate? 22) Do you consider that sufficient justification has been provided in the provision of new services? 23) Do you consider the proposed labour rates and fee-based prices to be reasonable
Questions on public lighting 24) Do you consider Ergon and Energex's public lighting proposal generally incorporates stakeholder inputs from this pre-lodgement engagement? If not, did Ergon and Energex communicate these potential departure points to stakeholders and provide adequate explanation during pre-lodgement engagement? 25) Do you support Ergon and Energex's proposed suite of public lighting services and prices? 26) Do you have any other comments on Ergon and Energex's public lighting proposal and their pre-lodgement engagement?

Glossary

Term	Definition
ADMS	Advanced Distribution Management Systems
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation capital expenditure
capex	capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	consumer energy resources
CESS	capital expenditure sharing scheme
CSIS	customer service incentive scheme
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
DNSP or distributor	Distribution Network Service provider
EBSS	efficiency benefit sharing scheme
F&A	framework and approach
GSL	guaranteed service level
ICT	Information and communication technologies
NEL	National Electricity Laws
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
opex	operating expenditure
RAB	regulated asset base
repex	replacement expenditure
RRG	Reset Reference Group
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme