Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper

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ENERGY QUEENSLAND
RESET REFERENCE GROUP

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1. Responses to Questions in AER Issues Paper

Consumer engagement 1) Do Ergon and Energex's proposals adequately reflect consumers' affordability concerns? *Response:* The affordability measures that relate to network controllable costs, while welcome, have a very small impact on affordability. More detail is provided in Section 4 of this report.
2) Have Ergon and Energex chosen the right topics to engage with consumers on? *Response:* Ergon and Energex engaged in depth with end consumers on a Customer Service Incentive Scheme and various aspects of tariff structure design. These were both appropriate topics for which end consumers were able to express clear preferences which were subsequently included in the regulatory proposals. Consumer views were canvassed relating to the desired speed of the energy transition, which was also an appropriate topic for engagement. The depth and breadth of engagement on other topics was limited due to time constraints. Specifically, this meant that beyond publication of Draft Plans, there was very little engagement on the capex and opex building blocks with consumers generally. Engagement with the RRG had a wider scope but that was still substantially less than is expected under the Better Resets Handbook or what RRG members have seen on other recent electricity distribution resets.
3) To what extent do you consider consumers were able to influence the topics Ergon and Energex engaged on? *Response:* The RRG made recommendations on scope early in the process when informed of the engagement time constraint by Energy Queensland. These recommendations sought to prioritise the engagement topics. The consumer forums had no real influence on topics chosen.
4) Are there topics that you would have preferred to consider in greater detail? Please give examples. *Response:* Yes. The RRG would have ideally preferred to see engagement across a wider range of topics, particularly in regard to overall capex and large customer tariffs changes and impacts. While the RRG would have preferred to see engagement with end consumers on resilience, we advised Energy Queensland not to proceed on the basis that in our experience, the limited timeframe available for engagement would not allow for meaningful and effective engagement on this complex topic.
Capital expenditure 5) Do you consider the AER's proposed approach to the ex-post review of Ergon's capex overspend is appropriate? *Response:* Yes, the overspend is very significant and consumers would benefit from access to a detailed bottom-up review on the efficiency and prudency of this expenditure.
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? *Response:* We do not have the information required to assess this and leave it to the AER to assess.

7) Do you consider Ergon and Energex's proposed responses to affordability concerns expressed by stakeholders are appropriate and achievable?[1] *Response:* Appropriate – no given their very small impact; achievable – remains to be seen but current period overspend suggests that there are risks to achieving the higher opex productivity.
7) Are there particular areas of Ergon and Energex's capex proposals that you would expect further engagement on[2]? *Response:* Given the limited scope of capex engagement so far, it will be difficult for Energex and Ergon to conduct any meaningful engagement on their capex proposals in the time remaining. Any further engagement would only be at the 'inform' level on the IAP2 spectrum.
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?[3] *Response:* No. There was very limited engagement on capex covering only a minor proportion of proposed capex spend.
8) Are there particular areas of Ergon and Energex's capex proposals that you would expect we place greater focus on in our review[4]? Response: We support the proposed close focus on the proposed areas of repex, augex, CER, cyber, fleet and property given the large increases for the current period 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? *Response:* For both Energex and Ergon, this seems to be the case based on the network's application the AER's base, trend step approach. However, we await the AER's decision on whether a base year adjustment is needed, particularly in the case of Energex. Aside from this we do not consider the AER's approach gives a result that reflects 'the efficient costs of a prudent operator' but this is a matter for a future AER network-wide review expected in 2026 and not a matter for consideration in this reset.
10) Do you consider Ergon and Energex's proposed responses to affordability concerns expressed by stakeholders are appropriate and achievable? *Response:* No. The opex affordability initiatives of a higher productivity factor total ~1.5% of total opex for both networks, a very small share of total opex. Based on current period experience, there are risks to achieving it.

[1] This is Question 7 in the 'Summary of questions' section on pp. 62-3 of the Issues Paper
[2] This is Question 7 at the end of the Capital Expenditure section on p.33 of the Issues Paper
[3] This is Question 8 in the 'Summary of Questions' section on p.62 of the Issues Paper.
[4] This is Question 8 at the end of the Capital Expenditure section on p.33 of the Issues Paper

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? *Response:* As we noted in our previous submission on Energex and Ergon's Engagement, there was only very limited consumer engagement on opex.
Incentive schemes 12) Do stakeholders agree with Ergon and Energex's proposal to not apply the CSIS? *Response:* Yes. Voice of Customer participants expressed a clear preference not to implement an incentive scheme for customer service.
13) Given Ergon and Energex did not propose to apply the CSIS, should the AER require them to apply the STPIS telephone answering parameter? *Response:* No. Application of the STPIS incentive scheme for telephone answering would not be consistent with the strong sentiments expressed by VoC customers. However, the RRG considers that removal of the STPIS telephone answering parameter must be contingent on an agreed alternative customer service reporting framework being in place.
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? *Response:* Yes. Customers argued that there should not be an incentive scheme relating to customer service. With no incentive scheme for telephone answering, it is reasonable to reduce the revenue at risk cap to 1.8% of total revenue. There is no evidence to indicate that the revenue at risk for other aspects of the STPIS scheme should be increased.
15) If Ergon and Energex do not apply a customer service scheme, what metrics should the AER track, if any, to ensure transparency? *Response:* The RRG expects that Energex and Ergon will engage broadly with customers and stakeholders to design the appropriate metrics and governance framework. The detailed framework needs to be included in the Revised Regulatory Proposal.
16) Do you have any views on the proposed application of any of the above incentive mechanisms? *Response:* While we support the application of the proposed incentive schemes as set out in the respective network proposals, we doubt the EBSS and CESS have the same incentive on prudent and efficient expenditure as they do in other DNSPS. We await the outcome of the Ergon ex-post review to test this proposition.
Tariff structure statements 17) Do you consider there are any aspects of Ergon or Energex's proposed TSSs that require adjustment?

Response: We believe that the current TSS for both networks provide a solid foundation, but more work needs to be done on engagement on the resulting tariffs that flow from the tariff structure engagement in 2023. While much of this is being achieved through the recently expanded Network Pricing Working Group, which includes the RRG members, we recommend greater engagement on C&I tariffs with impacted customers outside of the NPWG. We consider than more information is required to assure customers that the existing cross subsidy between non-solar and solar customers is not being preserved through the implementation of dynamic connections.
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? *Response:* Yes, the consultation indicated that residential and small business consumers were seeking a medium pace of reform based on the information that was provided.
Metering 19) Do you have any comments on the proposed cost recovery approach for legacy metering services? *Response:* The RRG supports the concept of the proposed change in charging arrangements for legacy metering services as it seeks to provide fair and equitable charging arrangements for customers, whilst supporting the objectives of the AEMC and the Queensland Government in achieving 100% smart meter deployment in Queensland by 2030. We note customer support expressed in engagement sessions for this concept as well.
20) Do you have any feedback about regulating the Mount Isa-Cloncurry network the same way as Ergon's grid-connected customers? *Response:* Whilst no specific customer engagement nor discussions with the RRG were undertaken on this issue, the RRG agrees that exempting customers from the AEMC reforms to create specific and different treatment would be burdensome, as well as potentially delaying or preventing the benefits of smart meters in this network.
Ancillary network services 21) Do you consider the rationalisation of the fee-based services appropriate? *Response:* The RRG was not involved in engagement with customers on this issue. We have no comment on this matter.
22) Do you consider that sufficient justification has been provided in the provision of new services? *Response:* The RRG was not involved in engagement with customers on this issue. We have no comment on this matter.
23) Do you consider the proposed labour rates and fee-based prices to be reasonable?

Response: The RRG was not involved in engagement with customers on this issue. We have no comment on this matter.
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? *Response:* In our Engagement Report the RRG notes that Ergon and Energex were prepared to listen to customer's formal and informal feedback and reflect that feedback in the Regulatory Proposal. We highlighted this bespoke program as an exemplary example of effective customer engagement.
25) Do you support Ergon and Energex's proposed suite of public lighting services and prices? *Response:* The RRG supports Ergon and Energex's proposed suite of public lighting services and prices based on the execution of an effective engagement process with its public lighting customers.
26) Do you have any other comments on Ergon and Energex's public lighting proposal and their pre-lodgement engagement? *Response:* We note that further work is required to engage with customers regarding public lighting in two key areas: 1. Forecasts of the estimated impacts for the regulatory period 2030-35. Initial discussions have been held, with Ergon and Energex forecasting significant increases for this period. Customers are seeking further detail regarding the drivers of these pricing impacts, including the assumed failure rates of LED lights. 2. The AEMC's consultation process and implications associated with the creation of Type 9 meters, the role of DNSPs in providing services and the likely costs associated with the deployment of smart public lighting cells.

2. Introduction

Energex and Ergon Energy network (Ergon) submitted their Regulatory Proposals for the period 2025-30 to the Australian Energy Regulator (AER) in January 2024. On 26th March 2024, the AER released an "Issues Paper for Ergon Energy and Energex electricity distribution determinations 2025–30" which "sets out our initial observations on the proposals and some areas in which we are particularly interested to hear from stakeholders"[5]. This submission is provided by Energy Queensland's independent Reset Reference Group (RRG). In it, we respond to the questions raised by the AER in the Issues Paper, as well as provide comments on other substantive elements of the businesses' Regulatory Proposals.

Acknowledgement

RRG members wish to acknowledge the assistance and support we have received from the Energy Queensland RDP2025 Project Team and subject matter experts. As well as providing 'deep dives' on various aspects of the Regulatory Proposals, the team has promptly responded to all of our requests for more information. Information has been shared openly with the RRG, with further briefings provided if required.

3. The Role of the Reset Reference Group

Energy Queensland's RRG is a five-member independent advisory group, comprising customer representatives from the Customer and Community Council together with external regulatory experts. The Reset Reference Group was established to work constructively with Energy Queensland on the development and implementation of the Customer and Stakeholder Engagement Plan underpinning the 2025-2030 Regulatory Proposal for Ergon Energy and Energex, and to challenge Energy Queensland on a range of matters relating to the substance of their Regulatory Proposals. Our over-riding objective is to ensure that customer needs and preferences are reflected in Energy Queensland's Regulatory Proposals and Revised Regulatory Proposals to the greatest extent possible.

The RRG has been working with Energy Queensland since November 2022. Since that time, we have met regularly with the Energy Queensland project team, the senior executive Steering Committee and the Energy Queensland Limited (EQL) Board Regulatory and Investment Committee (previously regulatory and Policy Committee). We have been able to contribute to the planning of elements of Energy Queensland's customer and stakeholder engagement program, as well as observe the majority of customer and stakeholder engagement events.

We have had the opportunity to closely examine several key aspects of Energy Queensland's revenue 'building block' components through 'deep dive' sessions provided by Energy Queensland subject matter experts. As members of Energy Queensland's Network Pricing Working Group (NPWG), the RRG has been deeply engaged on network tariff issues.

This submission to the AER is the third in a series of deliverables produced by the RRG. In October 2023, the RRG provided formal responses to the Ergon Energy and Energex Draft Plans[6]. In March

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[5] See p.2 https://www.aer.gov.au/documents/aer-issues-paper-energy-queensland-2025-30-dx-determination-march-2024-4

[6] See https://www.talkingenergy.com.au/rdp2025draftplans

2024, the RRG also prepared independent reports on Energex's and Ergon's customer and stakeholder engagement program which led to lodgement of the Regulatory Proposals in January 2024[7].

4. The Importance of Affordability

What are Energex and Ergon proposing?

Consultation on this reset is occurring at a time of significant community and business wide concerns about cost of living and the costs of doing business. Affordability has become the critical issue for households and businesses.

Both Energex and Ergon have highlighted the challenge of preparing a proposal that recognises the importance of affordability. For example, Energex's consumer engagement showed that while consumers value the services Energex provides, they have told Energex that (p.41)[8]:

> "…they have also told us that affordability of electricity is their primary concern, both from a cost-of-living and cost-of-business perspective."

Ergon says (p.177):

> "Our proposal responds to customer concerns around affordability by driving down controllable aspects of our expenditure program without compromising safety or reliability of the network."

In response to these affordability concerns, Table 10, p.54 summarises how Energex is responding (there is an identical Table in the Ergon proposal – Table 10 p.54).

[7] See https://www.talkingenergy.com.au/rdp2025

[8] Throughout this submission pages references to the Ergon and Energex submission refer to the respective Regulatory Proposal summary document https://www.aer.gov.au/system/files/2024-02/Energex%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public.pdf (Energex) and https://www.aer.gov.au/system/files/2024-02/Ergon%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public_0.pdf (Ergon)

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

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

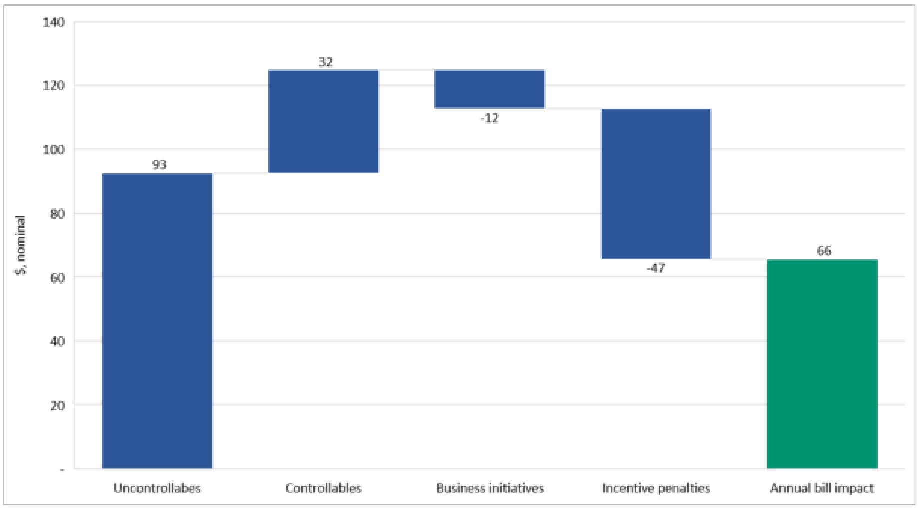
The following table summarises the average annual nominal and (real[9]) increase in annual network charges (including transmission and jurisdictional schemes) bill impacts for residential, small business and large businesses connected to the low voltage network over the 2025-30 period.

	Ergon[10]	Energex[11]
Residential	6.0% (3.20%)	5.0% (2.20%)
Small business	6.8% (4.00%)	6.2% (3.40%)
Large LV business	7.1% (4.30%)	6.6% (3.80%)

Graphs are presented on the relative impact of 'controllable' and 'uncontrollable' factors on the residential bill. This is Ergon's (p.169):

[9] Based on the Ergon and Energex placeholder assumed annual CPI of 2.80%; See Ergon p.165
[10] See Table 73 p.168
[11] See Table 75 p.167

Figure 54: Drivers of indicative annual residential bill increase



The $66 average annual nominal bill increase is a combination of $93 of uncontrollable factors (interest rates and inflation) and $32 of controllable factors that are partially offset by business initiatives to reduce prices, and opex and capex incentive scheme penalties from the current period. The corresponding graph for Energex shows a lower annual increase of $35 because of lower uncontrollables, a negligible contribution to higher prices from controllables and a minor impact (-$3) from business initiatives.

<u>AER comments</u>

The AER refers to the measures that Ergon and Energex have proposed to address affordability concerns and Question 10 asks whether these measures are 'appropriate and achievable'.

<u>RRG comments</u>

As we noted in our separate submission on engagement, affordability was clearly the most important issue in the consumer engagement we observed. This conclusion is the same in all other network resets RRG members have been involved in over the last couple of years and is consistent with many other community sentiment surveys. There is always a difficult and complex balance between the prudent and efficient expenditure required to meet Energex's and Ergon's statutory obligations and meeting customer needs in a growing economy. The RRG is focussed on challenging both networks to achieve this balance and address customers' affordability concerns through its operational efficiencies, rather than relying on Government rebates or self-funding capex overspend to address affordability concerns.

We do appreciate both Energex and Ergon responding positively to our recommendation for the 1% opex productivity and then applying the same improvement to capex overheads. On the other matters shown as affordability measures:

- It remains to be seen whether the shareholder's decision to self-fund Ergon's spend above forecast ICT (which reduces total revenue by $109m[12]) will be an affordability measure because of the current ex-post review. This review may well conclude that this expenditure was not

[12] Ergon p. 162

prudent and efficient. If so, this will impact on the reduction available to Ergon customers who do not benefit from the Uniform Tariff Policy.

- For Energex the same shareholder decision is a welcome affordability measure given actual capex for the 5 year ex-post period is 5.7% below the AER forecast. This has an impact on Ergon residential customers given the Uniform Tariff Policy.
- More cost reflective tariffs will provide an affordability benefit to those consumers who are able to take advantage of them. However, revenue cap regulation means that the lower revenue from those customers utilising the new tariffs will have to be recovered from other customers who do not or are unable to move to the cost reflective tariffs. The more customers who move to the cost reflective tariffs the greater the ceteris paribus price increase for those who do not – simply through the maths of revenue cap regulation. While some idea of the impact might be gleaned from the networks' Network Bill Impacts Attachments[13], there is no clear data on the potential impacts. Neither Energex nor Ergon engaged on this issue.
- There may be an argument for an implicit affordability benefit in the lack of opex step changes with the only one proposed being related to acquisition of smart meter data – though the revised proposal may have one related to inspecting private property poles. Both Energex and Ergon removed step changes relating to cyber security and increased insurance premiums that were in the Draft Plans. In recent and current resets, other networks have proposed (though not always successfully) step changes related to cyber security, resilience, insurance, CER integration and innovation.
- The proposal to exclude the telephone answering service component of STPIS is an affordability measure, but the amount involved is negligible.

The table below provides a rough calculation of the very small customer impact of these affordability measures.

Affordability measure	Reduction in proposed revenue 2025-30 ($m)	
	Energex	Ergon
Increase in opex productivity of 1%/yr vs requirement of 0.5%	$34.4m	$34.9m
1% productivity in capitalised overheads	$1.5m	$1.2m
Shareholder self-funding of ICT	$107.5[a]	
Total	$143.4m	$35.4m
Total revenue 2025-30 including EQ affordability measures	$8,151m	$7,819m
Affordability measures as % of total revenue before EQ affordability measures	1.7%	0.4%
Annual benefit/customer[b]	$16.87	$8.63[c]
Average annual residential customer bill in 2024-25[d]	$2,400	$2,400
% decrease in annual bill	0.7%	0.4%

a. Energex proposal p. 161
b. Based on average 2025-30 customer numbers of 1.7m for Energex and 820,000 for Ergon
c. Before application of the UTP which would bring the saving to the Energex level for residential and small businesses

[13] Energex https://www.aer.gov.au/system/files/2024-02/Energex%20-%209.02%20-%20Network%20Bill%20Impacts%20-%20January%202024_0.pdf; Ergon https://www.aer.gov.au/system/files/2024-02/Ergon%20-%209.02%20-%202025-30%20Network%20bill%20impacts%20-%20January%202024%20-%20public.pdf

d. Based on the AER's final default offer for 2024-25 for an Energex customer with controlled load[14]; Ergon assumed to be the same as Energex under the UTP

Further, the bill impact data presented in the proposals only shows averages and does not show range. The following data was provided to the RRG by Energy Queensland for both Energex and Ergon. Unlike the numbers above, these prices reflect just the impact of the January 2024 proposal (so assume there is no reduction in Ergon's RAB from the ex-post review) and exclude transmission costs and jurisdictional schemes and the impact on Ergon residential and small business customers of the Uniform Tariff Policy. Because of these exclusions, this data is a much more accurate view of the affordability impact of the proposals themselves.

Energex

	Nominal % increase in DUOS									
	1 July 2025		1 July 2026		1 July 2027		1 July 2028		1 July 2029	
	Range	Average	Range	Average	Range	Average	Range	Average	Range	Average
SAC										
Residential	2.6 to 16.5	11.6	6.0 to 9.1	7.4	5.5 to 8.3	6.7	4.7 to 7.3	6.1	5.3 to 8.5	6.3
Small Bus	-4.7 to 32.4	11.7	3.6 to 9.2	7.3	3.9 to 7.4	6.5	2.8 to 7.7	6.5	3.7 to 7.6	6.2
Large	-19.7 to 28.0	12.9	2.4 to 10.4	6.5	5.9 to 10.4	7.2	4.7 to 7.5	5.8	6.2 to 10.3	7.2
CAC	-33.5 to 32.9	0.9	0.6 to 18.9	8.0	2.9 to 16.1	7.8	3.0 to 15.2	8.0	3.0 to 14.4	8.0
Mining	-10.9 to 11.5	1.9								
Retail	-17.9 to 23.2	0.2								
Hotel & club	-12.4 to 26.4	-2.4								
Transport	-12.4 to 18.3	7.8								
ICC Range of price rises	-10.0 to 11.8	7.2								

Ergon Energy Network (Pricing region East)

	Nominal % increase in DUOS									
	1 July 2025		1 July 2026		1 July 2027		1 July 2028		1 July 2029	
	Range	Average	Range	Average	Range	Average	Range	Average	Range	Average
SAC										
Residential	0 to 14.7	7.9	5.1 to 14.3	8.5	5.4 to 10.3	8.3	4.6 to 9.5	7.8	6.5 to 11.9	8.8
Small bus	-9.9 to 22.0	7.9	2.1 to 11.0	8.6	2.1 to 9.9	8.4	2.1 to 9.8	7.8	2.3 to 10.0	8.5
Large	-27.7 to 19.7	8.1	7.1 to 13.1	9.1	5.7 to 9.9	8.0	6.1 to 10.5	7.4	6.6 to 11.2	8.6
CAC	-17.3 to 23.6	7.6	-1.3 to 20.5	7.3	-1.2 to 18.5	7.2	-1.2 to 16.9	7.2	-1.2 to 15.6	7.1
Mining	-17.3 to 22.6	2.0								
Retail	9.2 to 12.3	11.1								
Hotel & club	-0.3 to 12.8	9.4								
Community Infrastructure	-8.7 to 22.9	9.3								
ICC Range of price rises	4.4 to 9.3	7.5								

The tables show that the average nominal (and hence real) increases are sometimes much higher than the networks presented in their proposals. They also show a very wide range in the price increases with significant rises of over 15% for each of the 5 years for large Energex and Ergon CAC customers which get no benefit from the Uniform Tariff Scheme or Government rebates.

During preparation of their proposals Energex and Ergon engaged with large customers on a range of tariff structures eg high voltage time of use tariff trial. Other engagement covered two way and load control tariffs and streamlining of tariffs to be offered. However, we are unaware of any engagement with these large customers to discuss these proposed annual price increases over 2025-30 shown in the above tables. These customers may indicate conditional support for a new tariff structure, but it is not possible to provide meaningful feedback until the customer has seen what the tariff level

[14] See p. 6 https://www.aer.gov.au/system/files/2024-05/AER%20-%20Final%20determination%20-%20Default%20market%20offer%20prices%202024%E2%80%9325%20-%2023%20May%202024.pdf

would be under the new structure given the proposed 2025-30 expenditure. This engagement needs to address matters such as:

- Whether the large increase is due to the ending of a legacy tariff and movement to a more cost reflective tariff
- The opportunities for the customer to transition to new tariffs over time or adjust its demand profile to benefit from another tariff
- Simply the result of controllable and uncontrollable factors in the networks' proposals.

While Ergon residential and small business customers are protected from the very large historic and proposed capex spend, this is not the case for larger customers. They will bear the full cost of that spend which is why they are keen to see the AER undertake a very thorough review of Ergon's ex-post and 2025-30 proposed capex.

In summary, the RRG is not convinced that the proposals address the affordability issue in other than a very minor way. The level of consultation on affordability issues, particularly with large customers, is well below what would be expected under the AER Better Reset's Handbook.

5. Consumer Engagement

In March 2024, the RRG provided the AER with two independent reports on Ergon and Energex Engagement[15]. These reports:

- Evaluate the quality of customer engagement undertaken by Energex and Ergon in preparing their 2025-30 revenue proposals, scrutinising the methods employed, as well as the breadth and depth of engagement activities conducted,
- Assess the extent to which customer and stakeholder views have been considered and integrated into Energex and Ergon's regulatory proposal, and
- Analyse how well Energex and Ergon's approach to customer and stakeholder engagement aligns with the expectations set forth in the Better Resets Handbook.

We summarise our findings here.

Both networks approached customer engagement with the understanding that affordability, reliability, safety, and responsiveness to severe weather events were critical concerns for their customers. They recognized that customers expected a balance between cost-effective service provision and maintaining high standards in network safety and reliability, particularly in their response to emergencies. They also considered the increasing customer involvement in energy generation (e.g., solar installations), placed customers at the centre of energy discussions.

While these are all important issues, as the engagement progressed it became increasingly evident that affordability was clearly the primary focus of all customers, small and large and wherever they were located. With the requirements of managing the networks for reliability, and customer interface with the grid for behind the meter resources, the cost of doing this became central.

Engagement breadth and depth were limited to – customer service (CSIS), small parts of capex (some ICT, property, EVs, DER enablement) and public lighting, and more efficient tariff structures. The RRG

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[15] See https://www.talkingenergy.com.au/rdp2025

concluded that the engagement fell well short of what was expected under the AER's Better Resets Handbook and what RRG members had observed in other recent electricity distribution resets.

6. Capital Expenditure

6.1 Energex Capital Expenditure

<u>What is Energex proposing?</u>

Energex submit (p.79):

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

They point to the need to have enough capacity to meet peak demand across the network, to facilitate growing solar exports, respond to emergencies and major weather events and business systems to run the network. Affordability concerns are addressed by (p.17):

> "…driving down the controllable aspects of our capex program without compromising the safety or reliability of the network."

The table summarises recent history of AER allowances, actual and forecast spend in the current period and Energex's proposed spend in 2025-30[16].

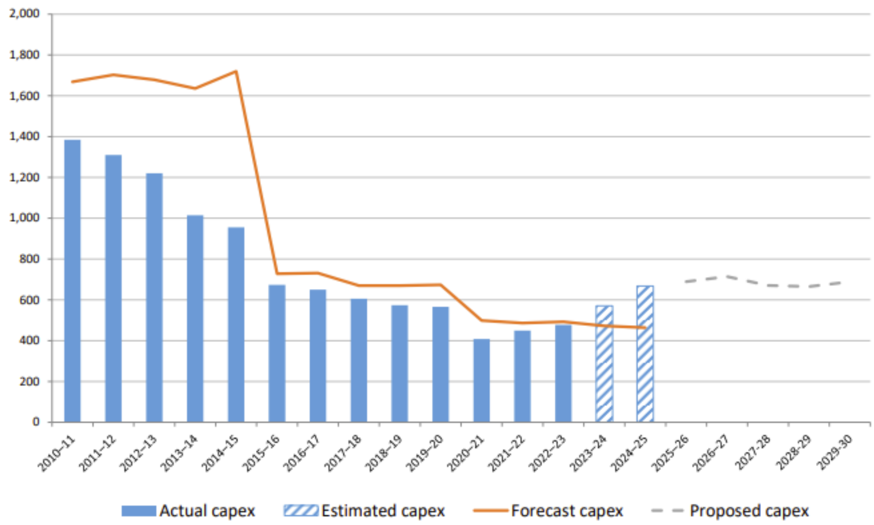
[16] See p.29 https://www.aer.gov.au/system/files/2024-03/AER%20-%20Issues%20Paper%20-%20Energy%20Queensland%20-%202025-30%20Dx%20Determination%20-%20March%202024_2.pdf

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%**

Energex is proposing capex of $3,422m in 2025-30, a 22% increase compared with forecast expenditure in the current period. Current period expenditure is, in turn, 15% above the AER allowance. The overspend in the current period is concentrated in the final two years and is in contrast with the underspend in 2010-15 and 2015-20[17].

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



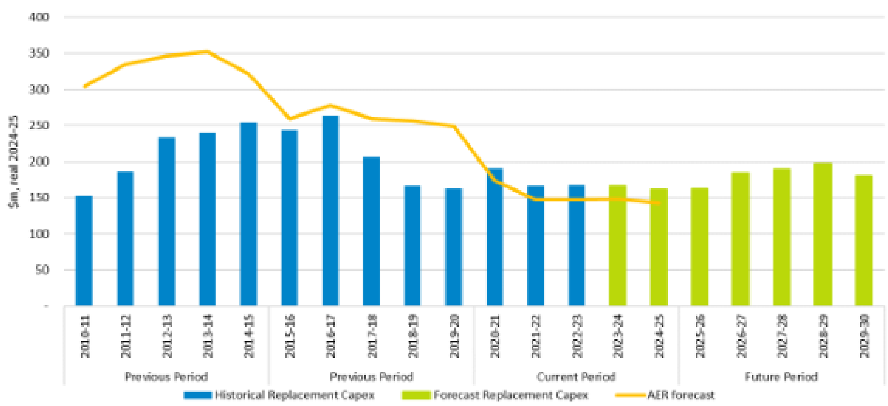
[17] Ibid p.28

The main category is repex (27%) with a 7% increase proposed on the current period forecast. The proposed repex (p.88):

> "…is in line with our long-term historic average for replacement and represents a continuation of our existing asset management practices."

Energex set out in their Strategic Asset Management Plan[18], their safety, environmental and regulatory obligations and the application of their Cost Benefit Framework and Principles[19].

Figure 27: Replacement capex between 2015 to 2030 ($m, real 2024-25)

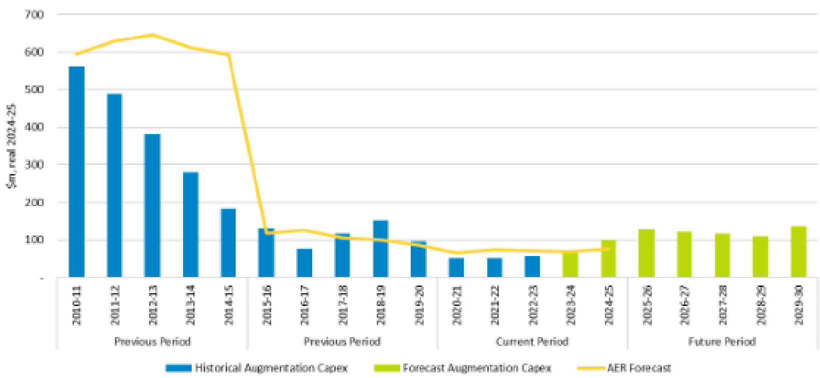


Energex submit that given most consumers have said that they are provided with a reliable electricity supply, they have the balance between cost and reliability 'about right' (p.88) and hence repex is based on maintaining the current level of reliability.

The largest category increase is in augex which is 18% of total capex and is forecast to increase 87% over forecast 2020-25 expenditure. This is driven by strong customer and demand growth, compliance obligations (eg clearance to ground, Safety Net security and worst feeder requirement under their Distribution Authority) and monitoring initiatives. In sub-transmission and distribution growth the spare capacity resulting from the large investment in the 2010-15 stemming from the Sommerville Inquiry and stricter security standards that were subsequently relaxed has been largely utilised.

[18] https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.04%20-%20Strategic%20Asset%20Management%20Plan%20%28SAMP%29%20-%20January%202024.pdf
[19] https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.05%20-%20Cost%20Benefit%20Framework%20and%20Principles%20-%20January%202024.pdf

Figure 29: Augex between 2015 to 2030 ($m, real 2024-25)



Some components of repex (three projects for a total of $39.1m) and augex ($25m) are being brought forward from 2030-35 to meet requirements for the 2032 Olympics.

Given the increase in capex, capitalised overheads increase 27% with Energex proposing a 1%/year productivity factor to capitalised overheads to address affordability concerns which reduces forecast revenue by $1.5m.

The main changes from the Draft Plan are a 6.2% increase in property expenditure due to more detailed project cost estimates being available for a major sub-station build and a 14.1% reduction in fleet expenditure due to a range of factors. Total capex is 3.3% higher than the Draft Plan.

Energex is proposing to exclude $130.2m ICT overspend from the RAB with the shareholder funding. Given actual spend in the ex-post capex review period (2018-19 to 2022-23) was 6% below the AER allowance, unlike Ergon, there will not be an ex-post review and actual capex can be rolled into the RAB without adjustment.

The CESS incentive scheme applied to Energex in the current period and the AER's Framework and Approach proposed to apply CESS version 2 to 2025-30 with its 'Bright Lined Tiered Test' variation to increase cost sharing going to consumers for underspend[20]. Energex supports the AER position.

AER comments

AER's preliminary assessment is that the capex proposal does not satisfy some aspects of the capex expectations in the Better Resets Handbook and there is insufficient information to assess whether it satisfies other expectations. Their focus will be on ~56% of capex which makes up the major components of the increase on the current period forecast – repex, augex, connections, CER and cyber.

While the preliminary assessment suggests the forecast repex is below the repex model threshold, the AER is assessing material Energex submitted to determine 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.

[20] https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf

<u>RRG comments</u>

Customer Engagement

Energex submits that customer views around maintaining current levels of reliability and safety have informed their capex proposal. This is based on the annual Queensland Household Energy Survey which covers Powerlink, Ergon and Energex. The 2023 survey[21] found that:

- 73% of respondents answered that these networks '…provide my household with a reliable energy supply'
- 60% of respondents replied that these networks '…gave me a sense of security about my electricity supply and
- 75% or respondents answered that "The existing balance between cost and reliability is about right"

There was no detailed engagement on these matters during the reset specific engagement. As discussed in our separate Engagement Report, there was some capex-related engagement, through the Customer Focus Groups, on issues where customers could influence the outcome:

- DER expenditure options for a component of the proposed $56m DER capex relating to increased rooftop solar export capacity; there were three levels of expenditure – 'slow and steady' ($0m), 'build up pace' ($12m) and 'fast and furious' ($60m) with associated bill impacts on different customer classes; there was a preference for the 'build up pace' option with affordability a key concern which is reflected in the proposal
- The siting of depots in industrial or residential areas with a preference for industrial areas; no real discussion on costs occurred
- Transitioning the vehicle fleet to EVs - again a choice between 'slow and steady', 'build up pace' and 'fast and furious' with a preference for somewhere between slow and steady and build up pace, with affordability again being a key factor
- ICT – options on various elements of customer service – enhancing call centre technology to handle more calls ($2.28m); adding enhanced broader digital online channels (additional $9.52m resulting in a total of $11.8m) or adding ability to assist customers with DER knowledge (additional $5.23m resulting in a total of $17m). The options were presented at a conceptual level, rather than specific customer service enhancements.

In summary, consultation where consumers could influence the outcome, was undertaken on a total of ~$20-25m or <1% of proposed capex. The overall Draft Plan capex trends were presented generally in an 'inform' context - what was proposed by component and total and why it was increasing. There was little sense that consumers had any ability to influence that expenditure.

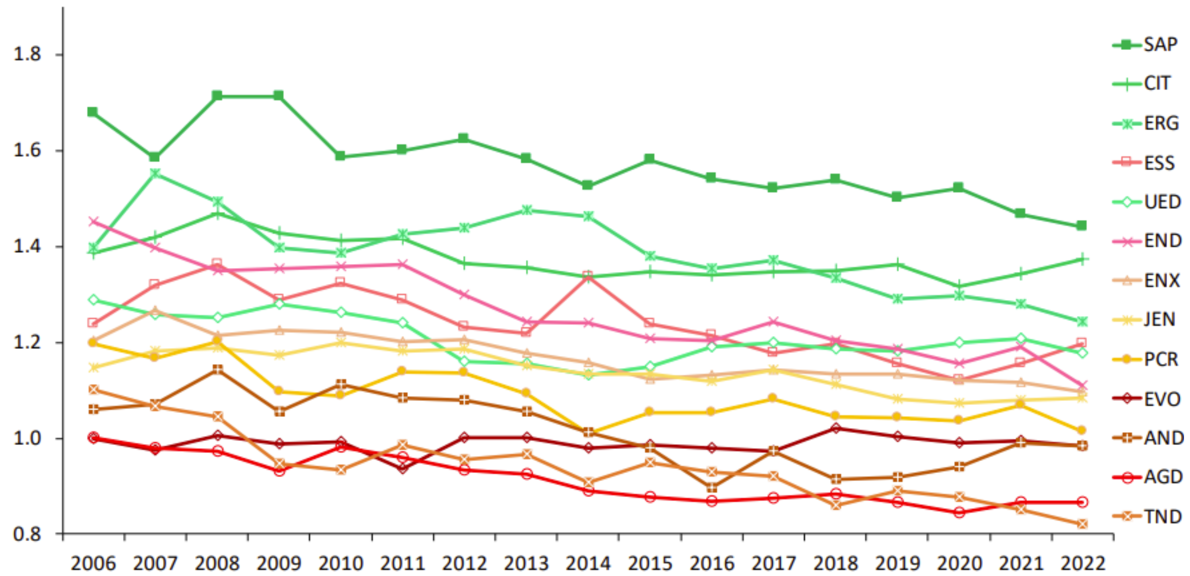
There was more extensive engagement with the RRG subsequent to the submission of Energex's proposal in January 2024. This covered asset management strategy, cost benefit framework, risk quantification, Olympics related capex, case studies on pole replacement, ICT governance, innovation, CER/DER and the history of 'boom and bust' investment cycle that Energex is seeking to move away from. Again, this was at the 'inform' level with the RRG having no influence on the level of expenditure. We comment on some of these below.

[21] https://qhes.com.au/queensland-household-energy-survey-2023/electricity-sentiment-2023/

Energex productivity

The AER's annual benchmarking report shows that their measure of Energex capex productivity (which does have some limitations) has been falling continually over the period 2007 to 2022, no different to most other DNSPs[22].

Figure 15 DNSP capital MPFP indexes under the preferred approach to addressing capitalisation differences, 2006–2022



Economic evaluation and governance

In its Draft Decision for 2020-25 capex, the AER was very critical of EQ's capex evaluation methodology saying that it did not meet the capex criteria in a number of areas. For example, in the case of the LV network safety and asbestos programme, the AER concluded that Energex did not demonstrate that their proposal reflected the capex criteria[23]:

> "We acknowledge the importance of investment to address safety risks and we have approved safety-related capex in previous decisions. However, we remain of the view that the costs of this program are grossly disproportionate to the benefits of mitigating the health and safety risks. Energex currently manages the safety risks associated with broken neutrals adequately and in line with industry good practice. There have been no incidents of serious injury or death caused by broken neutrals in Energex's network."

The AER went on to discuss their concerns with Energex's business case and cost-benefit analysis eg not basing the assumptions about probability and consequence of risks on historical experience leading to overstated forecast risk costs that do not reflect the consequence costs incurred by Energex as a result of neutral failure to date. This overstatement of the risks inflated the forecast repex required to mitigate that risk. While subsequent information provided by Energex led to the

[22] See p.38 https://www.aer.gov.au/system/files/2023-11/2023%20Annual%20Benchmarking%20Report%20%E2%80%93%20Electricity%20distribution%20network%20service%20providers%20%E2%80%93%20November%202023.pdf

[23] See pp.5-21-22 https://www.aer.gov.au/system/files/Final%20decision%20-%20Energex%20distribution%20determination%202020-25%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20June%202020_0.pdf

AER accepting the revised Energex capex proposal that was almost the same as their original proposal, the concern about Energex's business case and cost benefit analysis remained.

Since then, Energex has put a lot of effort into improving its capital governance around asset management and economic evaluation methodology and has had a number of sessions with the RRG to explain the changes. Its approach is described in a range of documents submitted as part of its 2025-30 proposal [24].

From our experience with other networks[25], Energex is still on the 'maturity journey' to put in place best practice asset management and project evaluation. This is particularly seen in the partial implementation of Copperleaf which has been delayed by problems implementing a major ICT systems upgrade discussed below. Energex hope to complete implementation over the coming year. Another example will be how safety is considered in asset management framework given the AER comments cited above. Good asset management is not about ignoring safety, it is about better understanding of the safety risk to make better informed expenditure decisions.

It is unclear how much this additional systems capacity will influence their ability to respond to AER information requests or the revised proposal given project evaluations are still in excel spreadsheets and Energex do not appear to have utilised the Copperleaf features eg around sensitivity and scenario testing. We have seen the benefits first hand of the full implementation of Copperleaf with it being a central part of Endeavour Energy's 2024-29 capex proposal that was accepted at the Draft Decision stage by the AER[26].

We leave the AER to assess whether Energex's improvements in project evaluation and governance have assisting in them in meeting the capex criteria.

Unit rates

Energex, like all companies undertaking construction activities, have seen considerable cost pressures over the last 4 years due to a combination of commodity prices, supply chain pressures, the falling $A and local labour costs. This trend is expected to continue over the 2025-30 period with many reports forecasting the shortage of labour and materials across the construction and major projects landscape[27].

Energex provides a Cost Comparison submission based on DNSP RIN data (excluding Ergon) to show its position compared to the mean and median (including and excluding outliers) of other networks

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[24] See its Strategic Asset Management Plan https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.05%20-%20Cost%20Benefit%20Framework%20and%20Principles%20-%20January%202024.pdf, its Cost Benefit Framework and Principles https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.05%20-%20Cost%20Benefit%20Framework%20and%20Principles%20-%20January%202024.pdf and its https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.05%20-%20Cost%20Benefit%20Framework%20and%20Principles%20-%20January%202024.pdf and Network Risk Framework https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.06%20-%20Network%20Risk%20Framework%20-%20January%202024.pdf

[25] See the description of the Endeavour framework provided to the AER as part of its 2024-29 revenue proposal https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2024%E2%80%9329/proposal

[26] https://www.aer.gov.au/system/files/2023-10/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Endeavour%20Energy%20-%202024-29%20Distribution%20revenue%20proposal%20-%20September%202023.pdf

[27] https://www.infrastructureaustralia.gov.au/publications/2023-infrastructure-market-capacity-report

for the four years from 2018-19 to 2021-22[28]. Compared to the median, Energex was below in all years for HV reconductoring, below for three of the years for pole replacement, below for two years for transformers and above for three years for LV reconductoring. Energex submits that[29]:

> "By ensuring that our forecast costs are in line with our historic efficient delivery of work, we have demonstrated that our regulatory proposal utilises efficient costs for the 2025-2030 regulatory control period. The unit rate review conducted by Turner and Townsend has also demonstrated that our costs for discrete project work is also within industry benchmarks, reflecting that our overall program costs compare favourably with industry benchmarks."

We have two comments:

- It is unclear from the data whether the lower costs come from a like for like comparison. The data does not show, for example, whether the Energex approach to bundling has an impact on costs. Another network may just replace the pole that needs to be replaced. Energex may replace the pole that needs to be replaced and also the pole next to it or the pole top transformer on it that might not need to be replaced for another 5-10 years. The replacement might be efficient but it may not be prudent.
- How indicative is analysis of Energex's relative position in the four years to 2021-22 of the current and expected situation in 2025-30? Yes, all networks will face increased cost pressures. But Energex will have the added pressure of a market seeking to implement the Queensland Energy and Job Plan, the Olympics build, other infrastructure projects including new housing build commitments at the same time as a new Energy Queensland EBA and the impact of the State Government's recent Best Practice Industry Conditions (BPIC) changes[30] that will considerably increase labour costs. Even though Energex is not directly impacted by BPIC given its project values are below the $100m threshold, it is in the same labour market as those Government owned entities that are subject to BPIC[31]. None of these factors, all of which increase the likelihood of expenditure above allowance, are discussed in the Cost Comparison submission.

While the 2025-30 forecast might be based on historic rates, the issue for consumers is how confident should they be of Energex actually achieving those rates and delivering the project list proposed and spending at or below the AER allowance? While Energex may argue that initiatives like bundling do offer an opportunity for controlling unit rates, how confident should consumers be that bundling is also prudent?

Non-recurrent ICT

In its 2020-25 Proposal Energex submitted that[32]:

[28] https://www.aer.gov.au/system/files/2024-02/Energex%20-%205.2.08%20-%20Cost%20Comparison%20of%20Energex%20RIN%20Unit%20Costs%20to%20the%20NEM%20-%20January%202024.pdf
[29] Ibid p.14
[30] https://www.epw.qld.gov.au/__data/assets/pdf_file/0014/20435/best-practice-industry-conditions.pdf
[31] https://www.abc.net.au/news/2024-04-10/qld-bpic-agreement-between-queensland-government-and-unions/103689030
[32] See p.77 https://www.aer.gov.au/system/files/Energex%20-%201.003%20Regulatory%20Proposal%202020-25%20-%20January%202019.pdf

> "This digital transformation will enable realisation of Energy Queensland's forecast 10% reduction in indirect costs and 3% improvement in program of work labour costs."

The AER Draft Decision was that the proposed ICT spend did not meet the capex criteria and provided a substitute estimate which was a reduction of 46% with the major portion of the reduction in non-recurrent ICT. While the concept of consolidation of disparate systems into a single Energy Queensland wide system (referred to as the DEBBs portfolio) was expected to deliver multiple real benefits[33]:

> "Energex is unlikely to deliver the program as proposed. To reduce delivery risks, a prudent and efficient distributor would not include all of the ICT projects Energex has proposed for completion within the 2020–25 regulatory control period. The proposed program is large scale, complex and an interdependent program of works impacting on a number of core IT systems and business processes. There is a significant risk that Energex will be unable to deliver the program in the timeframe proposed."

In its revised proposal, Energex accepted the Draft Decision with a minor adjustment and noted[34]:

> "We have taken on board AER and stakeholder feedback regarding the cost estimates and deliverability risks associated with the "Non-Recurrent ICT Capex Program" and accept the AER's substitute position. Energex will continue to manage program delivery within the reduced forecast, maximising delivery efficiency with priority on risk mitigation, sustainability, security and productivity enablement."

The AER approved allowance for 2020-25 was $176m. Forecast expenditure is $397m, 126% above the allowance. Energex's shareholder has decided to bear $130.2m of the cost overspend and not pass that on to consumers.

While forecast expenditure for 2025-30 at $266m is a 33% reduction on forecast in 2020-25, it is still a 51% increase on the 2020-25 allowance. Energex's focus in 2025-30 will be on (p.115):

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

The large over expenditure in the current period has been driven by a cost overrun in implementation of the DEBB ERP EAM Component Suite of Initiatives or DEBBs portfolio. Energex's explanation for the overrun was the additive complexity of the activities within the DEBBs portfolio which eventually included 48 separate projects. DEBBs was designed to manage the programmes and projects required to support the harmonisation of the Energex and Ergon network business process and tools after the two entities were merged in May 2016. After considerable challenges over 2017-23, the DEBBs portfolio was stopped in February 2023. Following a review, delivery was

[33] See p.5.52 https://www.aer.gov.au/system/files/AER%20-%20Energex%202020-25%20-%20Draft%20decision%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20October%202019_0.pdf

[34] See p.30 https://www.aer.gov.au/system/files/Energex%20-%20Revised%20Proposal%20-%201.003%20-%20Revised%20Regulatory%20Proposal%20-%20December%202019.pdf

restarted under a Transformation Portfolio which is now operating under a new structure and leadership.

The RRG has had a high-level presentation on the confidential draft post implementation review (PIR) completed by Deloitte. We raised a number of issues, particularly around the level and scope of risk analyses undertaken at all stages of the project development and implementation and await Energy Queensland's response. Some of the responses we have received so far suggest that the scope given to Deloitte was unusually narrow for a review of this size and importance. The fact that the DEBBs portfolio was approved to continue until early 2023 despite the cost overruns and the involvement of an independent assurance advisor raises questions about Energy Queensland's ICT governance processes. We understand that Section 5 of the ICT Plan has now been updated to incorporate the lessons from the DEBBs PIR.

We support the AER's views in its Non-network ICT capex assessment approach that networks should voluntarily provide ICT PIRs of up to 10 of the largest ICT projects within the previous 5 years. This is not for the purpose of the ex-post review which assesses capital against NER capital expenditure objectives and capital expenditure criteria. The intention is to improve transparency around ICT expenditure. As the AER notes[35]:

> "PIR's can service the businesses' best interest by demonstrating the prudency and efficiency of an ICT expenditure proposal."

We encourage Energex to share the final report with the AER when the RRG is available to provide its detailed comments to the AER.

On its 2020-25 initial revenue proposal Energex submitted that[36]:

> "This digital transformation will enable realisation of Energy Queensland's forecast 10% reduction in indirect costs and 3% improvement in program of work labour costs."

The only evidence Energex has provided on the actual benefits achieved was in an RRG Deep Dive in March 2024 where it was argued:

> "New and upgraded digital systems and capability will help improve business productivity. While digital benefits are not explicitly accounted for in 2025-30 opex they do contribute to achieving the 1% productivity factor applied to opex for 2025-30."

We have no understanding whether any productivity benefits were effectively given to employees as part of the current EBA negotiations and how much was left for consumers who have paid the AER allowance. Even with the shareholder paying for the $130.2m ICT overspend[37], that still leaves the AER allowance to go into the RAB. The RRG has received no information that would support the view that even that allowed expenditure was 'prudent and efficient', though, under the rules, we

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[35] See p. 25 https://www.aer.gov.au/system/files/AER%20-%20Guidance%20Note%20-%20Non-network%20ICT%20capex%20assessment%20approach%20for%20electricity%20distributors%20-%2028%20November%202019.pdf

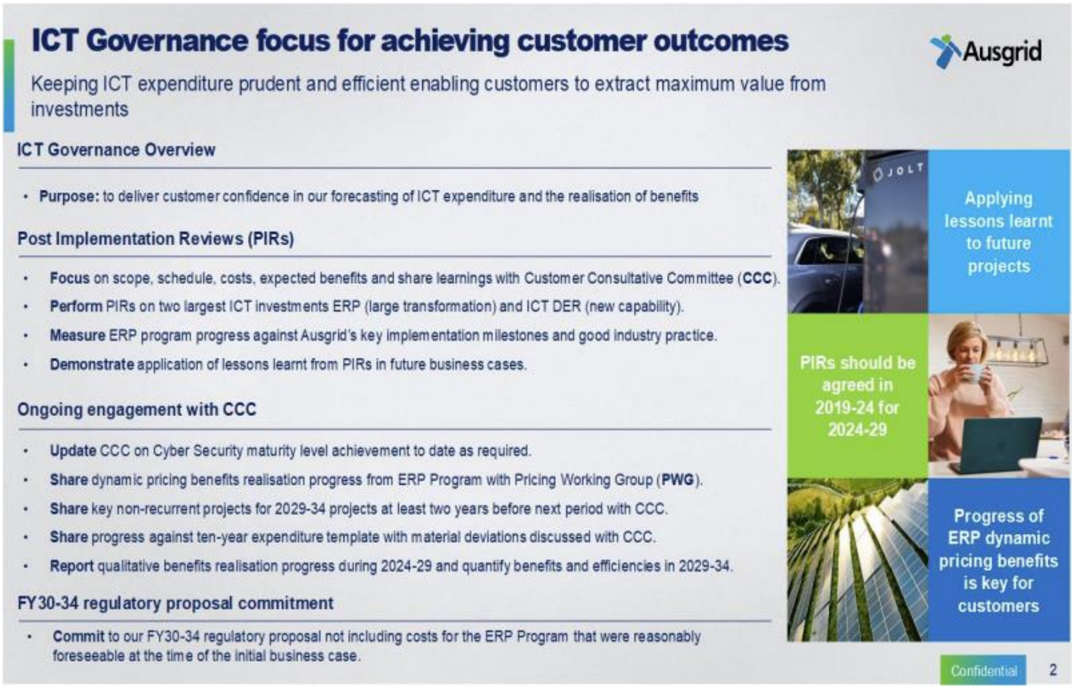
[36] See p.77 https://www.aer.gov.au/system/files/Energex%20-%201.003%20Regulatory%20Proposal%202020-25%20-%20January%202019.pdf

[37] Remembering as we pointed out above, it may be unlikely it would have been approved in the ex-post review in which case it would not have been included in the RAB independently of shareholder action. Further we note that this is only the overspend up the end of the ex post period in 2022-23. It does not cover the overspend in 2023-24 and 2024-25.

recognise that it will go into the RAB. We look forward to further analysis when the Transformation Portfolio implementation is completed.

Currently we have a low level of confidence that the revised 'end to end' ICT governance structure will result in a NPV positive project. The RRG has concerns about the Energy Queensland ICT governance process and ability to deliver the proposed suite of projects for 2025-30, including completion of the Transformation Portfolio, on time and on budget. We leave the AER to decide if the proposed ICT spend will meet their Guideline on non-recurrent ICT spend[38].

We would encourage Energy Queensland to consider the Ausgrid ICT governance framework that resulted from discussions with their Reset Customer Panel (RRG equivalent)[39].



Resilience

Our submission on the Draft Plan commented that Energy Queensland did not undertake engagement on resilience in addition to their BAU policies on Bush Fire Risk Management[40] and Natural Hazards Management (which includes their summer preparedness plans) which are regularly updated and which seek to take some account of the increased climate risks[41]. At this time other networks, especially Ausgrid, were actively engaging with their consumers and seeking to apply the

[38] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/non-network-ict-capex-assessment-review
[39] For a fuller discussion see pp. 56-7 https://www.aer.gov.au/system/files/Ausgrid%20-%20Reset%20Customer%20Panel%20-%20Att.%203.5%20-%20Independent%20report%20on%20Ausgrid%27s%202024-29%20revenue%20proposal%20-%2031%20Jan%202023%20-%20Public.pdf
[40] https://www.energex.com.au/__data/assets/pdf_file/0007/1013686/Bushfire-Risk-Management-Plan-2022-24.pdf
[41] https://www.energex.com.au/__data/assets/pdf_file/0006/1079493/Natural-Hazards-Management-Plan-2022-23.pdf

AER's recently published Resilience Guidance Note[42] which notes the close relationship between resilience and reliability. The compressed engagement schedule did not allow time for this engagement.

Olympics spend

There is a total of $64.1m capex spend ($39.1m repex and $25m augex) brought forward to meet Olympics requirements. We presume this is based on the facilities location in December 2023. We look forward to Energex providing further details on how sensitive this expenditure is to a change in major Olympic facilities' locations.

CESS

Under the incentive regulatory framework, incentive schemes are designed to encourage Energex to (p.144):

> "…run efficient businesses so that customers pay no more than is necessary for the services they require and ensure the right levels of service are delivered to customers."

Specifically (p.145):

> "…CESS incentivises us to undertake efficient capex over the regulatory control period by providing financial rewards and penalties for efficiency gains and losses on capex, respectively. Efficiency gains and losses are estimated as differences between the AER's capex allowances and actual capex. We share the efficiency gains and losses with customers.
>
> A symmetrical 30 per cent sharing ratio applies to overspends and underspends of capex. That is, if we underspend, we retain 30 per cent and customers receive 70 per cent of the benefit of underspending. Likewise, if we overspend, we incur 30 per cent and customers incur 70 per cent of the cost of overspending."

In its final report in April 2023 on the CESS review, the AER noted[43]:

> "For capex we also use a revealed cost approach. We have improved the way we use revealed costs in our forecasts by developing a replacement capital expenditure (repex) model and by refining other elements of our approach. As a result, the gap between our forecasts and actual expenditures has narrowed over time, from around 18 per cent for the first round of resets made after we introduced the CESS in 2013 to 7 per cent for current resets.
>
> Nevertheless, applying a revealed cost approach to capex is more difficult than opex because of the often lumpy and sometimes non-recurrent nature of capex. While replacement capital expenditure and elements of IT expenditure are largely recurrent, augmentations are not, especially for large new transmission projects. This means the CESS does not have the same information revelation properties as the EBSS and some forecasting error is inevitable."

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[42] https://www.aer.gov.au/industry/registers/resources/guidelines/aer-note-network-resilience

[43] See pp.5-6 https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf

The review resulted in a revised CESS scheme referred to as the Bright-Line Tiered Test. This reduces the rewards when a network business outperforms against its' approved forecast by more than 10% but maintains the same penalties for when its expenditure exceeds the approved forecast. The Test:

> "…has been designed to be asymmetric. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between the AER, consumers and the NSPs remains. The risk of us over forecasting capex requirements and a NSP subsequently underspending its forecast allowance remains higher than us under forecasting and a NSP overspending its forecast allowance. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error."

New transparency measures have also been implemented[44]:

> "… which will require NSPs to better explain the reasons for variations between opex and capex outcomes and forecasts. This will in turn assist stakeholders to better understand the extent to which genuine efficiency gains have driven expenditure outcomes, and the value of incentive payments."

Energex argues that:

- its historical underspend against the AER allowance in 2010-15 (30%) and 2015-20 (14%) while maintaining 'generally stable' reliability performance against Queensland Government Minimum Service Standard (p.84), plus
- various factors in the current period contributing to high inflation

supports its case that the forecast 15% overspend in the current period was required to '…ensure a safe and secure supply of electricity for our customers' (p.86). Similar arguments are advanced to support the 22% increase in forecast 2025-30 compared to forecast 2020-25.

Energex made a detailed presentation to the RRG on the 'boom and bust' investment cycle that occurred from 2000 – underinvestment in 2000-2004 when peak demand was increasing significantly; significant increase in investment from 2004 which extended into the 2010-15 reset period in response to the Sommerville inquiry and a range of changes to improve service and security standards (particularly with the mandated N-1 security standard). Their approach in 2025-30 is to move away from this investment cycle and move to a longer term sustainable capex programme.

The RRG certainly supports a move to the concept of a more sustainable capex programme – the issue for the AER is whether the proposed 'sustainable' programme meets the capex criteria. We offer the following comments.

It is unclear how much of Energex's underspend in 2010-2020 was due to:

- considerable spend in the 2005-2010 period as result of the Sommerville inquiry that significantly tightened reliability standards to a strict N-1 standard[45]

[44] See p.6 https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf
[45] Energex 'capital operation expenditure' more than doubled from 2003 to 2005 - $401m to $840m https://www.afr.com/markets/commodities/energy-crisis-just-a-storm-away-20050919-jekv9

- the subsequent relaxing of the standards following the 2011 Electricity Network Capital Program Review[46] that found the tighter standard imposed in 2005 were not justified given the large increase in power prices that resulted from substantially increased expenditure that resulted in the 'gold plating' debate, and
- a reflection of the AER's then forecasting ability

rather than the Energex representation as a matter of efficiency. Energex acknowledge (p.84):

> "… the lower spend was partially in response to a relaxation of reliability standards following the 2011 Review"

but provide no quantification of that impact. From the RRG's perspective:

- the AER allowance for 2010-15 was set prior to the 2011 Review; we would expect that allowed capex would have been considerably lower had the AER had the benefit of that review when it was deciding the 2010-15 allowance, and
- the AER's ability to counter the network's information asymmetry was considerably lower than it is now eg there was no repex model at that time.

The RRG is not convinced that the reduction in expenditure over 2010-20 is all due to improved efficiency, particularly when the productivity data cited above shows a continual decline in productivity since 2007. Neither is the RRG convinced that the proposed increase in 2025-30 can be justified on the basis of a 'recovery' in required expenditure given the 2010-20 spend profile.

In the F&A, the AER summarised the changes flowing from the CESS review and concluded that CESS would apply in 2025-30[47]. Our concern is not about the AER over-forecasting and the network subsequent underspending – which in any case is handled by the tiered incentive structure for underspend. Our concern is that there will be a repeat of what has happening with Energex in the current period with the severe cost pressures expected over 2025-30. Our concern is if the AER reduces the allowed capex due to Energex not meeting the capex criteria but Energex still spends over the allowance due to a combination of underestimated unit rates and a decision to spend above allowance on projects Energex considers are 'prudent and efficient' that were not approved by the AER.

While Energex will share 30% of the cost overrun, we are not convinced that this incentive works the same way with Energex as it would work with a privately owned network. There is still the risk of a future ex-post review, though the materiality threshold may still mean consumers pay for inefficient capex spend. However, we submit that this not an efficient way of running a network.

While the CESS revisions last year pick up the asymmetric risk consumers face from underspend, it does not cover the asymmetric risk on overspend that is historically more likely in Energy Queensland than other networks. This table is similar to the one above – showing the forecast total capex spend for the current period at the time of the Initial proposal compared to the AER allowance[48].

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[46] https://documents.parliament.qld.gov.au/tp/2014/5414T5363.pdf
[47] See p.16 https://www.aer.gov.au/system/files/AER%20-%20Final%20Framework%20and%20Approach%20%20-%20Ergon%20and%20Energex%202025-30%20-%20June%202023_1.pdf
[48] Information provided by the AER.

2019-24	Actual/forecast spend in January 2023 compared to approved allowance for 2019-24
Ausgrid	-13%
Endeavour	-7%
Essential	-7%
2020-25	Actual/forecast spend in January 2024 compared to approved allowance for 2020-25
Energex	14%
Ergon	76%
SAPN	0%

It suggests that the drive to meet the allowance is perhaps weaker for Ergon and Energex that other networks. While we do support the application of CESS to Energex's capex spend in 2025-30, we are not confident that it acts as the same efficiency incentive that it does for privately owned networks.

6.2 Ergon Capital Expenditure

What is Ergon proposing?

Ergon submit that (p.78):

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

They point to the need to have enough capacity to meet peak demand across the network, to facilitate growing solar exports, respond to emergencies and major weather events and business systems to run the network. Affordability concerns are addressed by (p.17):

> "…driving down the controllable aspects of our capex program without compromising the safety or reliability of the network."

The table summarises recent history of AER allowances, actual and forecast spend in the current period and Ergon's proposed spend in 2025-30[49].

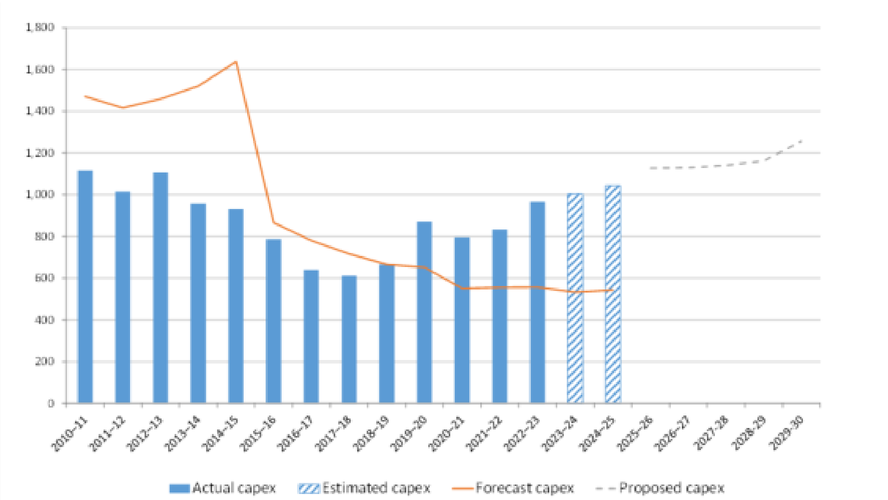
[49] See p.22 https://www.aer.gov.au/system/files/2024-03/AER%20-%20Issues%20Paper%20-%20Energy%20Queensland%20-%202025-30%20Dx%20Determination%20-%20March%202024_2.pdf

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%**

Ergon is proposing capex of $5,805m in 2025-30, a 20% increase compared with forecast expenditure in the current period. Current period expenditure is, in turn, 74% above the AER allowance. The overspend in the current period is in contrast to the underspend in the last two preceding regulatory control periods[50].

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



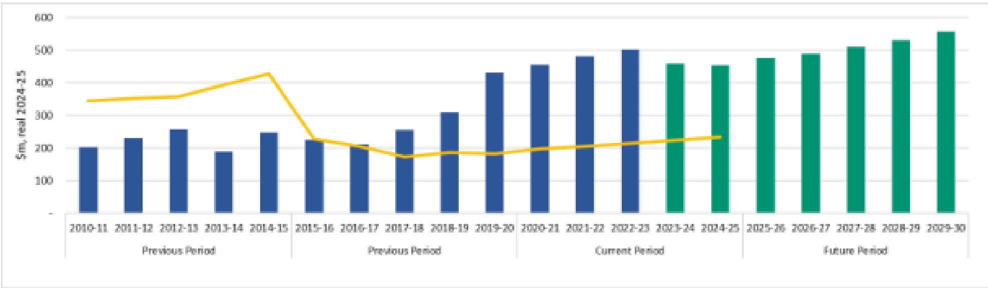
The main category is repex (44%) with a 10% increase proposed on the current period forecast (which is 118% above the AER allowance). Ergon submitted that given most consumers have said that

[50] Ibid p.19

they are provided with a reliable electricity supply, they have the balance between cost and reliability 'about right' (p.89), the proposed repex:

> "….is in line with our long-term historic average for replacement and represents a continuation of our existing asset management practices (refer to Figure 28)"

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



Ergon discuss the history of major investments in the 1970s and 1980s that are reaching the end of their serviceable lives in the current and next regulatory control periods. Ergon took prudent actions to extend the lives from 2010-2017 but further extensions are not possible due to safety risks and reliability impacts. Many assets are reaching end of life in 2020-25 and 2025-30 so Ergon cannot avoid replacement any longer. This issue is particularly seen with pole replacements where the average annual volume of replacements of 3,600 in 2010-17 out of a total population of one million inferred an asset life of 230 years. Given a significant number of poles were installed in the 1970s and 1980s this low level of replacement could not continue. This led to a significant expansion on pole replacements in the current period and this is expected to continue in 2025-30. Overall repex is driven by Ergon's asset management objectives[51] and the application of their cost benefit framework and principles[52].

Repex programmes falls into two categories – condition and risk (prior to in-service failure or defects) and reactive (following an in-service failure or where a defect is identified). Modelled repex comprising poles, overhead conductor, underground cables, switchgear, transformers and services comprises 64% of total repex. Ergon's analysis suggested that modelled repex (66% of total repex) is 17% above what the AER's repex model suggests.

Augmentation expenditure is the next biggest category forecast at 14% of total capex. This is increased significantly – 2020-25 forecast is 71% above allowance and 2025-30 is a further 80% increase on 2020-25 forecast. Ergon argue that it is in line with their long-term historic average:

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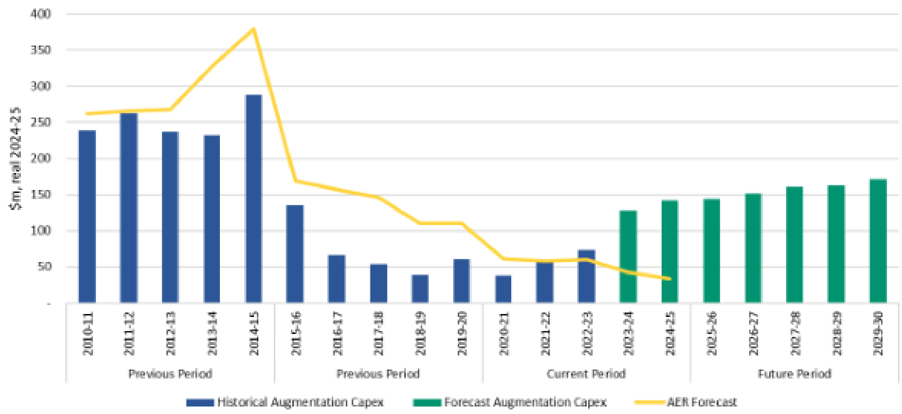
[51] https://www.aer.gov.au/system/files/2024-02/Ergon%20-%205.2.04%20-%20Strategic%20Asset%20Management%20Plan%20%28SAMP%29%20-%20January%202024%20-%20public.pdf
[52] https://www.aer.gov.au/documents/ergon-5205-cost-benefit-framework-and-principles-january-2024

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



as well as reflecting growing demand in a geographically dispersed aging network. Customers have benefited from the investment made 10-15 year ago as a result of the Government adopting the Sommerville Inquiry's N-1 security standard meaning augex was limited in over the 2016-23 period as asset utilisation increased.

There are large increases in fleet (42%) and property (23%) compared to forecast 2020-25. Connection expenditure remains constant and ICT falls 28% because of the expected completion of major upgrade project in the current period and the focus moving to system maintenance. Given the increase in capex, capitalised overheads increase 27% with Ergon proposing a 1%/year productivity factor to capitalised overheads to address affordability concerns which reduces forecast revenue by $1.2m.

The main changes from the Draft Plan are a $37m (4.9%) increase in augex and a reduction of $11m (14.9%) in DER. Total capex is $281m (5.1%) higher than the Draft Plan, though $37m of that is due to an error in the Draft Plan non-network ICT.

The CESS incentive scheme applied to Ergon in the current period and the AER's Framework and Approach[53] proposed to apply CESS version 2 to 2025-30 with its 'Bright Lined Tiered Test' variation to increase cost sharing going to consumers for underspend[54]. Ergon supports the AER position.

Ergon capex spend for the last five years that actual data is available – 2018-19 to 2022-23, was $1,308.5m (42.8%) above the AER allowance (p. 148).

[53] https://www.aer.gov.au/documents/aer-final-framework-and-approach-ergon-and-energex-2025-30-july-2023-0

[54] https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf

Table 60: Ex post review period capex

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

The main components of overspend are repex and non-network ICT. The main driver of the repex overspend was accelerated pole replacement.

This has triggered an AER ex post review of whether that additional capex is 'prudent and efficient'. Ergon considers that the overspend was prudent and efficient and the actual capex over this period can be rolled into the RAB without adjustment. However, Ergon will exclude the overspend in ICT ($121.3m) from the RAB that was incurred in the first three years of the current period. This cost will be borne by the shareholder. This leaves an overspend of $1,187.2m to be justified. Ergon has provided evidence to support its position that it is efficient and prudent.

<u>AER comments</u>

The AER's review is in two related parts:

- An ex-post review of Ergon's capex overspend in 2017-18 to 2022-23 which will be a bottom-up review of the main drivers of the overspend, whether Ergon applied appropriate project management and planning processes, whether the overspend was justifiable and, if it is not, how much is not efficient and prudent
- A review of the proposed 2025-30 capex

A key focus of the ex-post review will be a review of repex and these findings will have implications for the ex-ante review of proposed 2025-30 expenditure. The AER's preliminary assessment is that (p.27):

> "Ergon has not satisfied some aspects of the capex expectations of the Better Reset's Handbook, and at this stage there is insufficient information as to whether it satisfies some of the other capex expectations"

The AER's preliminary analysis of Ergon modelled repex for 2025-30 concluded the Ergon proposal is higher than the repex model and further analysis is underway. The AER will review the proposed $83m for resilience having regard to the AER's Resilience Guidance Note[55]. Connections capex will be reviewed to assess whether Ergon's development of more robust econometric modelling approach (compared to its 2020-25 forecasting approach) has achieved its objectives. There will be the usual assessment of the other expenditure categories according to relevant AER Guidance Notes.

<u>RRG comments on the ex-post review</u>

[55] https://www.aer.gov.au/industry/registers/resources/guidelines/aer-note-network-resilience

Ex post review

Under the rules the AER is required to decide whether the roll forward of the regulatory asset base (RAB) from the previous period contributes to the achievement of the capex incentive objective ie reflects the capex criteria. The review will cover actual capex for the last five years where auditable data is available – 2018-19 to 2022-23. Under the rules the AER may exclude capex from being rolled into the RAB in three circumstances:

- when a distribution business has overspent, the amount of capex above the total capex forecast that does not reasonably reflect the capital expenditure criteria can be excluded from the RAB
- where there is an inflated related party margin, the inflated portion of the margin can be excluded from the RAB, and
- where a change to a distribution business's capitalisation policy has led to opex being capitalised, the capitalised opex can be excluded from the RAB

The two stage process the AER follows is set out in our Capital Expenditure Incentive Guideline[56]:

Stage 1 - initial consideration of actual capex performance – is the overspend significant, what is the network's history of capex spend and are there any specific concerns?; if there are then,

Stage 2 – a deeper bottom up review of the capex overspend – what were the drivers and the network's management and planning tools and practices eg application of RIT-D, appropriate project management plans and processes including asset management, project delivery controls, procurement strategies, asset lifecycle management, resourcing strategies, program management and risk management; appropriate project and capital governance

The most recent example of this review is the AER's Draft Decision on Endeavour's 2024-29 proposed capex that reviewed actual capex for 2017-18 to 2021-22[57].

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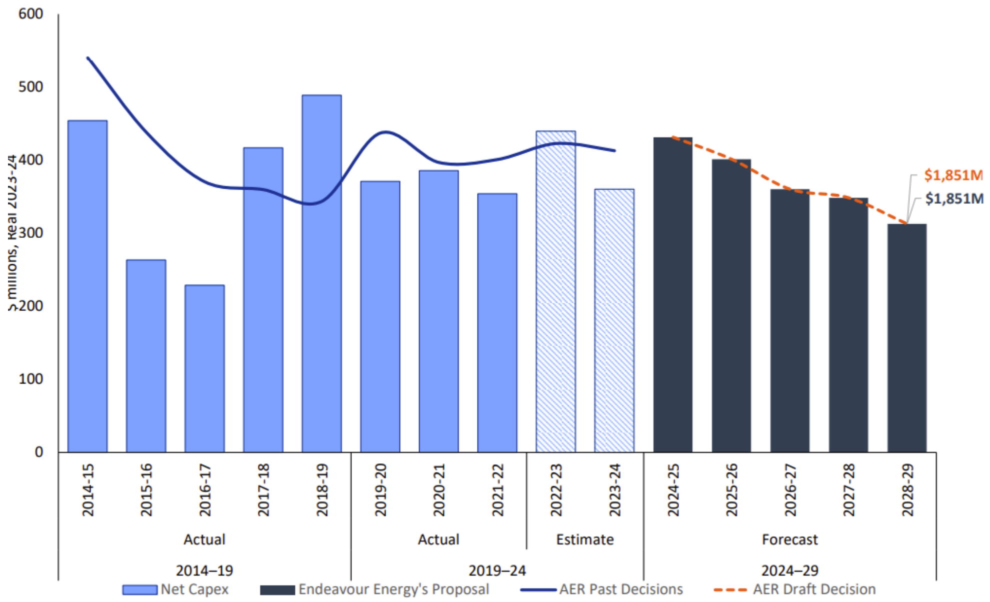
[56] See pp.13-19 https://www.aer.gov.au/system/files/AER%20capital%20expenditure%20incentive%20guideline%20-%20April%202023.pdf

[57] See pp.26-7 https://www.aer.gov.au/system/files/2023-10/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Endeavour%20Energy%20-%202024-29%20Distribution%20revenue%20proposal%20-%20September%202023.pdf

Figure 5.1 Endeavour Energy's historical and forecast capex ($ million, $2023–24)



Source: AER analysis. Capex is net of asset disposals and capital contributions.

While the overspend in those 5 years was ~$200m above the allowance, capex spend in 2014-15 to 2016-17 was ~$400m lower than the allowance. The AER agreed with Endeavour that it was simply a timing issue and concluded that:

> "…including Endeavour Energy's actual capex in the 2017–18 to 2021–22 regulatory years into the RAB is likely to contribute towards achieving the capex incentive objective."

Hence the AER's ex-post review did not proceed to Stage 2.

We understand this Ergon review is the first time in the 10 years since the rule was introduced that the AER has progressed to Stage 2. Figure 7 from the Issues Paper reproduced above shows why the AER concluded that the overspend is not a timing issue and the amount is certainly material. Ergon's actual capital is $1,308.5m (43%) above the AER's forecast with the main drivers being overspend of $1,191m (120%) in repex and ICT, with an overspend of $114m. Egon has said that it does not intend to recover ICT capex above the AER forecast. So, the Stage 2 bottom-up review will be of $1,194.9m with particular focus on repex covering:

- Main drivers and reason for overspend – review unit cost and volume changes, Ergon's asset management and governance arrangements, with a particular focus on pole replacement
- Whether Ergon applied appropriate project management and planning processes including internal governance
- How much of the overspend was efficient and prudent.

As the AER notes in the Issues Paper (p.21):

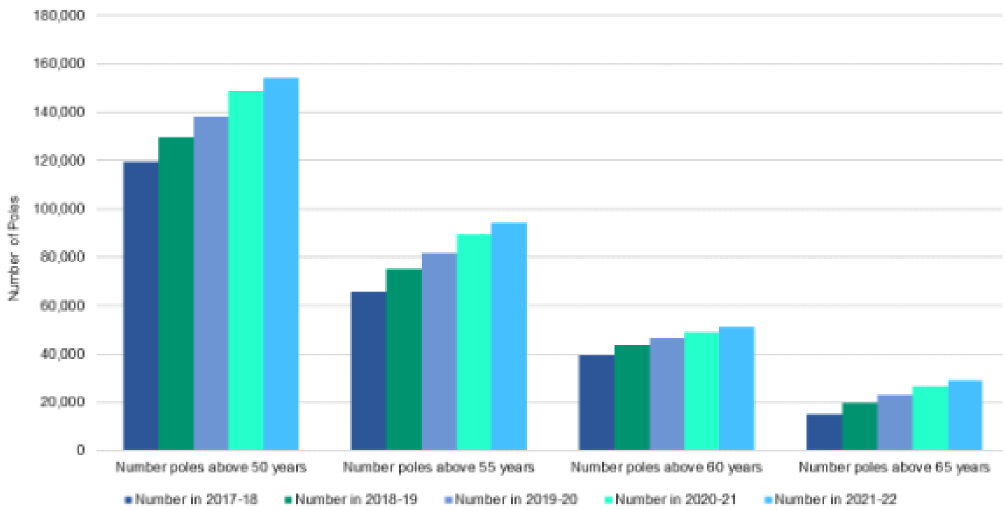
> "For repex, we understand that one of the drivers of the overspend is accelerated pole replacement, with the material step up in repex to be maintained over the forecast (2025-30) period. This means that our ex-post review will have implications for our review of Ergon's ex-ante 2025-30 forecast."

Ergon submits in its 2025-30 proposal that (p.83):

> "We manage our overall capital spend across the different categories of capex with a view to not materially exceed the total AER capex forecast for the regulatory control period."

The RRG has received briefings from Ergon on reasons for the repex overspend. There are four main categories that account for 85% of the overspend – pole replacement ($323m overspend), pole top structure replacement ($225m overspend), switchgear replacements ($265m overspend) and transformer replacements – especially those on poles ($202m overspend). Ergon also discussed the developing governance over 2017-2022 as it sought to better understand the pole replacement issue – the observed increase in unassisted pole failures, development of a management plan, independent expert reports, the change in the 'serviceability calculation', development of the internal business case that seemed to be too late for the AER 2020-25 decision timetable, Board consideration and further independent reports and a PIR that demonstrates the actual delivery of the higher capex 'is NPV positive and maximises the benefits to our customers'. This table is key data provided by Ergon to support its case.

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



The RRG's conclusion from this comprehensive analysis suggests that there was the need to considerably increase pole replacement to make-up for the under-replacement in previous periods. What we leave the AER to assess is whether the relatively constant unit rates over the ex-post period give rise to a prudency issue rather than an efficiency issue eg is it always prudent to 'bundle' work eg replace the cross arm or pole top transformer as well as the pole? We discuss this again below in the context of forecast unit rates for 2025-30. We can understand Ergon's proposal that even with the significant increase in pole replacement over recent years, the average age profile of its 1 million poles is increasing – which is why repex will remain high in 2025-30.

In summary, while the RRG was provided with a significant amount of information during these briefings, we were not in a position to critique Ergon's approach. We look forward to the results of the detailed AER review in the Draft Decision in September. We note that there is the possibility of another ex-post review in 2029 – forecast spend in the last two years of the current period is significantly above the AER allowance. It remains to be seen whether actual expenditure in the three years 2025-6 to 2027-28 is sufficiently lower than the AER allowance to balance that forecast overspend.

RRG comments on the forecast capital expenditure for 2025-30

Customer Engagement

Ergon submits that customer views around maintaining current levels of reliability and safety have informed their capex proposal. This is based on the annual Queensland Household Energy Survey which covers Powerlink, Energex and Ergon. The 2023 survey[58] found that:

- 73% of respondents answered that these networks '…provide my household with a reliable energy supply'
- 60% of respondents replied that these networks '…gave me a sense of security about my electricity supply and
- 75% or respondents answered that "The existing balance between cost and reliability is about right"

There was no detailed engagement on these matters during the reset specific engagement. As discussed in our separate Engagement Report, there was only very limited capex related engagement, through the Customer Focus Groups, on issues where customers could influence the outcome:

- DER expenditure options for a component of the proposed $63m DER capex relating to increased rooftop solar export capacity; there were three levels of expenditure – 'slow and steady' ($0m), 'build up pace' ($12m) and 'fast and furious' ($53m) with associated bill impacts on different customer classes; there was a preference for the 'fast and furious' but the 'build up pace' option was proposed to help address affordability concerns
- The siting of depots in industrial or residential areas with a preference for industrial areas; no real discussion on costs
- Transitioning the vehicle fleet to EVs - again a choice between 'slow and steady', 'build up pace' and 'fast and furious' with a preference for somewhere between slow and steady and build up pace with affordability again being a key factor
- ICT – options on various levels of customer service – enhancing call centre technology to handle more calls ($2.28m); adding enhanced broader digital online channels (additional $9.52m resulting in a total of $11.8m) or adding ability to assist customers with DER knowledge (additional $5.23m resulting in a total of $17m). The options were presented at a conceptual level, rather than specific customer service enhancements.

In summary, consultation where consumers could influence the outcome, was undertaken on a total of ~$20-25m or <1% of proposed capex. The overall Draft Plan capex trends were presented generally in an 'inform' context - what was proposed by component and total and why it was increasing. There was no sense that consumers had any ability to influence that expenditure.

There was more extensive engagement with the RRG subsequent to the submission of Ergon's proposal in January. This covered asset management strategy, cost benefit framework, risk quantification, case studies on pole replacement, ICT governance, innovation, CER/DER and the history of boom and bust' investment cycle that Ergon is seeking to move away from. Again this was

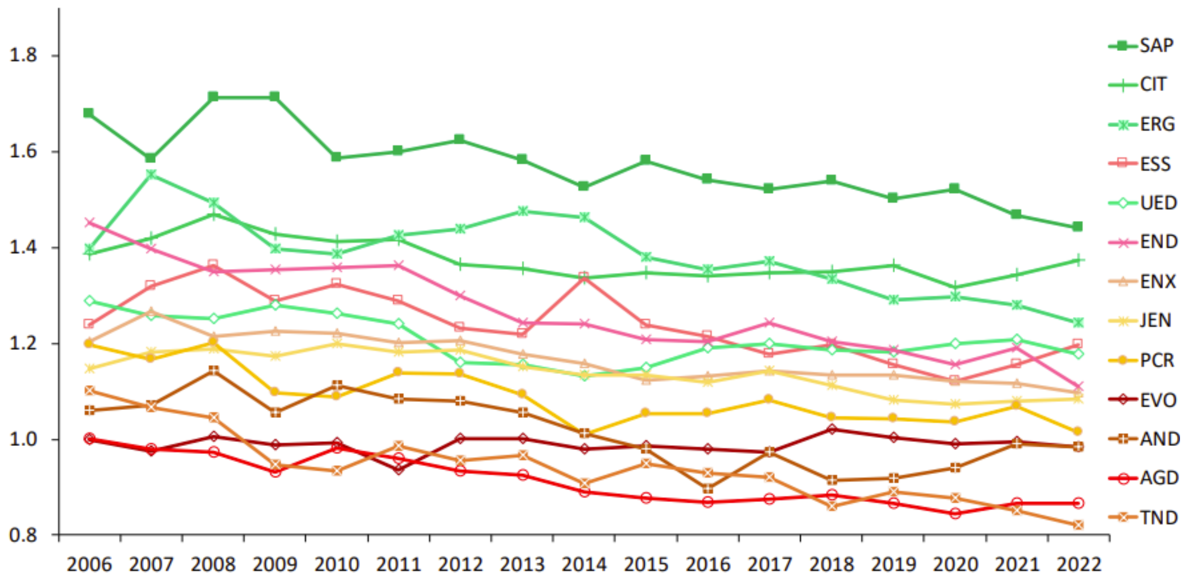
[58] https://qhes.com.au/queensland-household-energy-survey-2023/electricity-sentiment-2023/

at the 'inform' level with the RRG having no influence on the level of expenditure. We comment on some of these below.

Ergon productivity

The AER's annual benchmarking report shows that their measure of Ergon capex productivity (which does have some limitations) shows Ergon has been in the top three over the period 2007 to 2022. While that shows relative performance, Ergon's productivity, like most DNSPs, has been in continual decline over most of that period – in Ergon's case since 2013.

Figure 15 DNSP capital MPFP indexes under the preferred approach to addressing capitalisation differences, 2006–2022



Asset utilisation

Ergon claims that as a result of investment 10-15 years ago (p.101):

> "…combined with the change in security and reliability requirements prescribed by Safety Net obligations in our Distribution Authority, meant that we were able to rely on our existing sub-transmission capacity and limit our augex requirements in the 2015-20 and 2020-25 regulatory control periods. Our network utilisation increased during this period."

It is not clear whether the comment on network utilisation referred to the total network of just the sub-transmission component. The AER data on network utilisation shows that Ergon, while being above the DNSP average, had on average lower asset utilisation during 2015-22 that the previous 5 years[59].

	2006	2009	2012	2015	2017	2019	2021	2022
Ergon	0.71	0.77	0.64	0.57	0.53	0.56	0.54	0.61
Energex	0.50	0.50	0.45	0.39	0.43	0.43	0.41	0.44
DNSP Average	0.57	0.59	0.49	0.45	0.47	0.49	0.45	0.46

Economic evaluation and governance

[59] See the excel spreadsheet at https://www.aer.gov.au/documents/aer-electricity-dnsp-operational-performance-data-2006-22

In its Draft Decision for 2020-25 capex, the AER was very critical of Ergon's capex evaluation methodology saying that it did not meet the capex criteria in many areas. The lack of an expenditure justification meant that the AER could not complete a bottom-up alternative forecast and could only provide a substitute estimate based on trend – the actual and forecast spend in over 2015-20. More information was provided in the lead-up to the final decision but allowed capex was 19% below Ergon's revised forecast with the AER concluding[60]:

> "Our assessment highlighted that Ergon Energy's revised augex, repex and property forecasts would not form a total capex forecast that reasonably reflect the capex criteria, taking into account the capex factors and the revenue and pricing principles."

Since then, Ergon has put a lot of effort into improving its capital governance around asset management and economic evaluation methodology and has had a number of sessions with the RRG to explain the changes. Its approach is described in a range of documents submitted as part of its 2025-30 proposal[61].

From our experience with other networks[62], Ergon is still on the 'maturity journey' to put in place best practice asset management and project evaluation. This is particularly seen in the partial implementation of Copperleaf which has been delayed by problems implementing a major ICT systems upgrade discussed below. Ergon hope to complete implementation over the coming year. Another example will be how safety is considered in the asset management framework. Good asset management is not about ignoring safety, it is about better understanding of the safety risk to make better informed expenditure decisions.

It is unclear how much this additional capacity will influence their ability to respond to AER information requests or the revised proposal given project evaluations are still in excel spreadsheets and Ergon do not seem to have utilised the Copperleaf features eg around sensitivity and scenario testing. We have seen the benefits first hand of the full implementation of Copperleaf with it being a central part of Endeavour Energy's 2024-29 capex proposal that was accepted at the Draft Decision stage by the AER[63].

We leave the AER to assess whether Ergon's improvements in project evaluation and governance have assisting in them in meeting the capex criteria.

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[60] See pp.5-8 https://www.aer.gov.au/system/files/Final%20decision%20-%20Ergon%20Energy%20distribution%20determination%202020-25%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20June%202020.pdf

[61] See its Strategic Asset Management Plan https://www.aer.gov.au/documents/ergon-5204-strategic-asset-management-plan-samp-january-2024, its Cost Benefit Framework and Principles https://www.aer.gov.au/documents/ergon-5205-cost-benefit-framework-and-principles-january-2024 and its Network Risk Framework https://www.aer.gov.au/system/files/2024-02/Ergon%20-%205.2.06%20-%20Network%20Risk%20Framework%20-%20January%202024%20-%20public.pdf

[62] See the description of the Endeavour framework provided to the AER as part of its 2024-29 revenue proposal https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2024%E2%80%9329/proposal

[63] https://www.aer.gov.au/system/files/2023-10/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Endeavour%20Energy%20-%202024-29%20Distribution%20revenue%20proposal%20-%20September%202023.pdf

Unit rates

Ergon, like all companies undertaking constriction activities, have seen considerable cost pressures over the last 4 years due to a combination of commodity prices, supply chain pressures, falling $A and local labour costs. This trend is expected to continue over the 2025-30 period with many reports forecasting a shortage of labour and materials across the construction and major projects landscape[64].

Ergon provides a Cost Comparison submission based on DNSP RIN data (excluding Energex) to show its position compared to the mean and median (including and excluding outliers) of other networks for the four years from 2018-19 to 2021-22[65]. Compared to the median Ergon was below for all four years for pole replacement and HV reconductoring, below for three of the four years for LV reconductoring and transformer replacement. Ergon submits that[66]:

> "By ensuring that our forecast costs are in line with our historic efficient delivery of work, we have demonstrated that our regulatory proposal utilises efficient costs for the 2025-2030 regulatory control period. The unit rate review conducted by Turner and Townsend has also demonstrated that our costs for discrete project work is also within industry benchmarks, reflecting that our overall program costs compare favourably with industry benchmarks."

We have two comments:

- It is unclear from the data whether the lower costs come from a like for like comparison. The data does not show, for example, whether the Energex approach to bundling has an impact on costs. Another network may just replace the pole that needs to be replaced. Ergon may replace the pole that needs to be replaced and also the pole next to it or the pole top transformer on it that might not need to be replaced for another 5-10 years. The replacement might be efficient but it may not be prudent.
- How indicative is analysis of Ergon's relative position in the four years to 2021-22 of the current and expected situation in 2025-30? Yes, all networks will face increased cost pressures. But Ergon will have the added pressure of a market seeking to implement the Queensland Energy and Job Plan, the Olympics build, other infrastructure projects including new housing build commitments at the same time as a new Energy Queensland EBA and the impact of the State Government's recent Best Practice Industry Conditions (BPIC) changes[67] that will considerably increase labour costs. Even though Ergon is not directly impacted by BPIC given its project values are below the $100m threshold, it is in the same labour market as those Government owned entities that are subject to BPIC[68]. None of these factors are discussed in the Cost Comparison submission.

While the 2025-30 forecast might be based on these historic rates, the issue for consumers is how confident should they be of Ergon actually achieving those rates and delivering on the proposed significant increase in capex spend. While Ergon may argue that initiatives like bundling in pole replacement do offer an opportunity for controlling unit rates, how confident should consumers be that the bundling is also prudent?

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[64] https://www.infrastructureaustralia.gov.au/publications/2023-infrastructure-market-capacity-report
[65] https://www.aer.gov.au/documents/ergon-5208-cost-comparison-ergon-rin-unit-costs-nem-december-2023
[66] Ibid p.14
[67] https://www.epw.qld.gov.au/__data/assets/pdf_file/0014/20435/best-practice-industry-conditions.pdf
[68] https://www.abc.net.au/news/2024-04-10/qld-bpic-agreement-between-queensland-government-and-unions/103689030

Non-recurrent ICT

In its 2020-25 Proposal Ergon submitted that[69]:

> "This digital transformation will enable realisation of Energy Queensland's forecast 10% reduction in indirect costs and 3% improvement in program of work labour costs."

The AER Draft Decision was that the proposed ICT spend did not meet the capex criteria and provided a substitute estimate which was a reduction of 24% with the major portion of the reduction in non-recurrent ICT. While the overall objectives/goals of the non-recurrent ICT programme (referred to as the DEBBs portfolio) were endorsed[70]:

> "Ergon Energy's non-recurrent ICT capex forecast is not a reasonable forecast of prudent and efficient costs and Ergon Energy is unlikely to deliver the program in the timeframe proposed…
>
> …we do not consider that Ergon Energy will be able to deliver the program as proposed, and a prudent and efficient ICT program would not include all of the ICT projects proposed for the 2020–25 regulatory control period. The proposed program is large scale, complex and an interdependent program of works that impacts broadly across core IT systems and business processes. The risks of successful delivery of the program in the timeframe proposed, in terms of resourcing, implementation, business process change and the realisation of benefits appear high."

In its revised proposal, Ergon accepted the Draft Decision with a minor adjustment and noted[71]:

> "We have taken on board AER and stakeholder feedback regarding the cost estimates and deliverability risks associated with the "Non-Recurrent ICT Capex Program" and accept the AER's substitute position. Ergon Energy will continue to manage program delivery within the reduced forecast, maximising delivery efficiency with priority on risk mitigation, sustainability, security and productivity enablement."

The AER approved allowance for 2020-25 was $197m. Forecast expenditure is $400m, 103% above the allowance. Ergon's shareholder has decided to bear $121.3m of the cost overspend and not pass that on to consumers.

While forecast expenditure for 2025-30 at $288m is a 28% reduction on forecast in 2020-25, it is still a 46% increase on the 2020-25 allowance. Ergon's focus in 2025-30 will be on (p.116):

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

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[69] See p.76 https://www.aer.gov.au/system/files/Ergon%20Energy%20-%201.004%20-%20Regulatory%20Proposal%202020-25%20-%20January%202019_1.pdf
[70] See p.5.53 https://www.aer.gov.au/system/files/AER%20-%20Ergon%20Energy%202020-25%20-%20Draft%20decision%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20October%202019_0.pdf
[71] See p.30 https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Revised%20Proposal%20-%201.003%20-%20Revised%20Regulatory%20Proposal%20-%20December%202019.pdf76

The large over expenditure in the current period has been driven by a cost overrun in implementation of the DEBB ERP EAM Component Suite of Initiatives, known as the 'DEBBs portfolio'. Ergon's explanation for the overrun was that the complexity of the activities with the DEBBs portfolio which eventually included 48 separate projects. DEBBs was designed to manage the programmes and projects required to support the harmonisation of the Ergon and Ergon network business process and tools after the two entities were merged in May 2016. After considerable challenges over 2017-23, the DEBBs portfolio was stopped in February 2023. Following a review, delivery was restarted under a Transformation Portfolio which is now operating under a new structure and leadership.

The RRG has had a high-level presentation on the confidential draft post investment review (PIR) completed by Deloitte. We raised a number of issues, particularly around the level and scope of risk analyses undertaken at all stages of the project development and implementation and await Energy Queensland's response. Some of the responses we have received so far suggest that the scope given to Deloitte was unusually narrow for a review of this size and importance. The fact that the DEBBs portfolio was approved to continue until early 2023 despite the cost overruns and the involvement of an independent assurance advisor points raises questions about Energy Queensland's ICT governance processes. We understand that Section 5 of the ICT Plan has been updated to incorporate the lessons from the DEBBs PIR.

We support the AER's views in its Non-network ICT capex assessment approach that networks should voluntarily provide ICT PIRs of up to 10 of the largest ICT projects within the previous 5 years. This is not for the purpose of the ex-post review which assesses capital against NER capital expenditure objectives and capital expenditure criteria. The intention is to improve transparency around ICT expenditure. As the AER notes[72]:

> "PIR's can service the businesses' best interest by demonstrating the prudency and efficiency of an ICT expenditure proposal."

We encourage Ergon to share the final report with the AER when the RRG is available to provide its detailed comments to the AER.

In its 2020-25 initial revenue proposal Ergon submitted that[73]:

> "This digital transformation will enable realisation of Energy Queensland's forecast 10% reduction in indirect costs and 3% improvement in program of work labour costs."

In its 2025-30 proposal it says (p.85):

> "…we invested heavily in a major non-network ICT portfolio of works that involved transforming and consolidating core systems and business processes which has allowed us to work more efficiently and with a higher level of cyber security."

[72] See p. 25 https://www.aer.gov.au/system/files/AER%20-%20Guidance%20Note%20-%20Non-network%20ICT%20capex%20assessment%20approach%20for%20electricity%20distributors%20-%2028%20November%202019.pdf

[73] See p.76 https://www.aer.gov.au/system/files/Ergon%20Energy%20-%201.004%20-%20Regulatory%20Proposal%202020-25%20-%20January%202019_1.pdf

We agree with the 'invested heavily' comment but we are yet to see the benefits identified and measured. The only evidence Ergon has provided on the actual benefits achieved was in an RRG Deep Dive in March 2024 where it was argued:

> "New and upgraded digital systems and capability will help improve business productivity. While digital benefits are not explicitly accounted for in 2025-30 opex they do contribute to achieving the 1% productivity factor applied to opex for 2025-30."

We have no understanding whether any productivity benefits were effectively given to employees as part of the current EBA negotiations and how much was left for consumers who have paid the AER allowance. Even with the shareholder paying for the $121.3m ICT overspend[74], that still leaves the AER ICT allowance to go into the RAB. The RRG has received no information that would support the view that even that allowed expenditure was 'prudent and efficient', though, under the rules, we recognise that it will go into the RAB. We look forward to further analysis when the Transformation Portfolio implementation is completed.

Currently we have a low level of confidence that the revised 'end to end' governance structure will result in a NPV positive project. The RRG has concerns about the EQ ICT governance process and ability to deliver the proposed suite of projects for 2025-30 on time and on budget. We leave the AER to decide if the proposed ICT spend will meet their Guideline on non-recurrent spend[75].

We would encourage Energy Queensland to consider the Ausgrid ICT governance framework that resulted from discussions with their Reset Customer Panel (RRG equivalent)[76].

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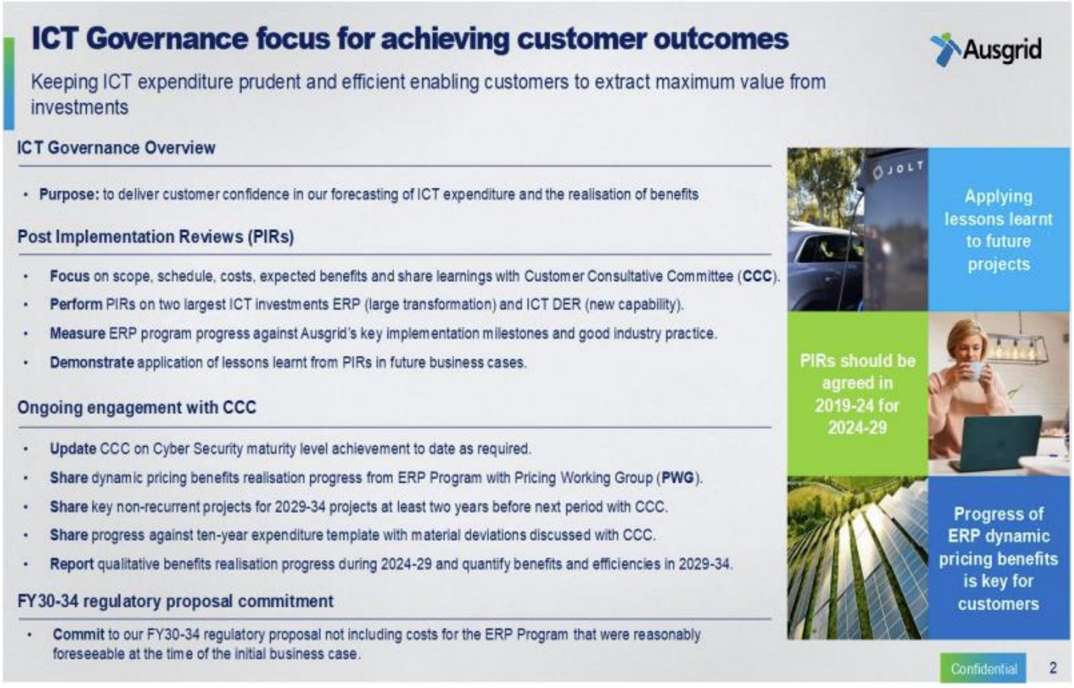
[74] Remembering as we pointed out above, it may be unlikely it would have been approved in the ex-post review in which case it would not have been included in the RAB independently of shareholder action. Further we note that this is only the overspend up the end of the ex-post period in 2022-23. It does not cover the overspend in 2023-24 and 2024-25.

[75] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/non-network-ict-capex-assessment-review

[76] For a fuller discussion see pp. 56-7 https://www.aer.gov.au/system/files/Ausgrid%20-%20Reset%20Customer%20Panel%20-%20Att.%203.5%20-%20Independent%20report%20on%20Ausgrid%27s%202024-29%20revenue%20proposal%20-%2031%20Jan%202023%20-%20Public.pdf



Resilience

Our submission on the Draft Plan commented that Energy Queensland did not undertake engagement on resilience in addition to their BAU policies on Bush Fire Risk Management[77] and Natural Hazards Strategy (which includes their summer preparedness plans) which are regularly updated and which seek to take some account of the increased climate risks[78]. At this time other networks, especially Ausgrid, were actively engaging with their consumers and seeking to apply the AER's recently published Resilience Guidance Note[79] which notes the close relationship between resilience and reliability. The compressed engagement schedule did not allow time for this engagement.

CESS

Under the incentive regulatory framework, incentive schemes are designed to encourage Ergon to (p.145):

> "…run efficient businesses so that customers pay no more than is necessary for the services they require and ensure the right levels of service are delivered to customers."

Specifically (p.146):

> "…CESS incentivises us to undertake efficient capex over the regulatory control period by providing financial rewards and penalties for efficiency gains and losses on capex, respectively. Efficiency gains and losses are estimated as differences between the AER's

[77] https://www.Ergon.com.au/__data/assets/pdf_file/0007/1013686/Bushfire-Risk-Management-Plan-2022-24.pdf
[78] https://www.ergon.com.au/__data/assets/pdf_file/0006/1079493/Natural-Hazards-Strategy-2023-24.pdf
[79] https://www.aer.gov.au/industry/registers/resources/guidelines/aer-note-network-resilience

> capex allowances and actual capex. We share the efficiency gains and losses with customers…
>
> A symmetrical 30 per cent sharing ratio applies to overspends and underspends of capex. That is, if we underspend, we retain 30 per cent and customers receive 70 per cent of the benefit of underspending. Likewise, if we overspend, we incur 30 per cent and customers incur 70 per cent of the cost of overspending."

In its final report in April 2023 on the CESS review, the AER noted[80]:

> "For capex we also use a revealed cost approach. We have improved the way we use revealed costs in our forecasts by developing a replacement capital expenditure (repex) model and by refining other elements of our approach. As a result, the gap between our forecasts and actual expenditures has narrowed over time, from around 18 per cent for the first round of resets made after we introduced the CESS in 2013 to 7 per cent for current resets.
>
> Nevertheless, applying a revealed cost approach to capex is more difficult than opex because of the often lumpy and sometimes non-recurrent nature of capex. While replacement capital expenditure and elements of IT expenditure are largely recurrent, augmentations are not, especially for large new transmission projects. This means the CESS does not have the same information revelation properties as the EBSS and some forecasting error is inevitable."

The review resulted in a revised CESS scheme referred to as the Bright-Line Tiered Test. This reduces the rewards when a network business outperforms against its' approved forecast by more than 10% but maintains the same penalties for when its expenditure exceeds the approved forecast. The Test:

> "…has been designed to be asymmetric. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between the AER, consumers and the NSPs remains. The risk of us over forecasting capex requirements and a NSP subsequently underspending its forecast allowance remains higher than us under forecasting and a NSP overspending its forecast allowance. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error."

New transparency measures have also been implemented[81]:

> "… which will require NSPs to better explain the reasons for variations between opex and capex outcomes and forecasts. This will in turn assist stakeholders to better understand the extent to which genuine efficiency gains have driven expenditure outcomes, and the value of incentive payments."

Ergon argues that it (p.83):

> "…manage(s) (its) overall capital spend across the different categories of capex with a view to not materially exceed the total AER capex forecast for the regulatory control period."

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[80] See pp.5-6 https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf
[81] Ibid

Its 18% underspend against AER allowance from 2010-11 to 2018-19 led to $99.2m (p.83) being returned to customers providing bill relief to customers.

Ergon made a detailed presentation to the RRG on the 'boom and bust' investment cycle that occurred from 2000 – underinvestment in 2000-2003 when peak demand was increasing significantly; significant increase in investment from 2003-2010 in response to the Sommerville inquiry and a range of changes to improve service and security standards (particularly with the mandated N-1 security standard) [82]. Ergon submits that while they took prudent actions to extend asset life during 2010-17, further deferral was not possible given (p.90):

> "…a large volume of the network was constructed in the 1970s and 1980s and these assets are reaching the end of their serviceable lives in the current and next regulatory control periods … but (Ergon is) now unable to continue to avoid replacing these assets due to safety risks and reliability impacts."

The RRG certainly supports the intent of the Ergon's approach. The issue for us which the AER will address is whether the proposed spend meets the capex criteria. We offer the following comments.

It is unclear how much of Ergon's underspend in 2010-2018 was due to:

- considerable overspend in the 2005-2010 period as a result of the Sommerville inquiry that significantly tightened the reliability standard to a strict N-1 standard[83]
- the subsequent relaxing of the standards following the 2011 Electricity Network Capital Program Review[84] that found the tighter standard imposed in 2005 were not justified given the large increase in power prices that resulted from the substantially increased expenditure that resulted in the 'gold plating' debate, and
- a reflection of the AER's then forecasting ability

rather than the Ergon representation as a matter of efficiency. Ergon acknowledge (p.83):

> "… the lower spend was partially in response to a relaxation of reliability standards following the 2011 Review"

but provide no quantification of that impact. From the RRG's perspective:

- the AER allowance for 2010-15 was set prior to the 2011 Review; we would expect that allowed capex would have been considerably lower had the AER had the benefit of that review when it was deciding the 2010-15 allowance, and
- the AER's ability to counter the network's information asymmetry was considerably less than it is now eg there was no repex model at that time.

The RRG is not convinced that the reduction in expenditure over 2010-17 is all due to improved efficiency, particularly when the productivity data cited above shows a continual decline in productivity since 2013. The RRG looks forward to the AER review to see whether the proposed increase in 2025-30 can be justified on the basis of continuing the 'recovery' begun to 2017-18.

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[82] Ergon 'capital operation expenditure' more than doubled from 2003 to 2005 - $401m to $840m https://www.afr.com/markets/commodities/energy-crisis-just-a-storm-away-20050919-jekv9
[83] https://www.afr.com/markets/commodities/energy-crisis-just-a-storm-away-20050919-jekv9
[84] https://documents.parliament.qld.gov.au/tp/2014/5414T5363.pdf

In the F&A, the AER summarised the changes flowing from the CESS review and concluded that CESS would apply in 2025-30[85]. Our concern is not about the AER over-forecasting and the network subsequent underspending – which in any case is handled by the tiered incentive structure for underspend. Our concern is that there will be a repeat of what has happening with Ergon in the current period with the severe cost pressures expected over 2025-30 combined with an inability to deliver on their promised works programme. If the AER reduces the allowed capex due to Ergon not meeting the capex criteria, Ergon may still spend over the allowance due to a combination of underestimated unit rates and a decision to spend above allowance on projects Ergon considers are 'prudent and efficient' that were not approved by the AER.

While Ergon will share 30% of the cost overrun, we are not convinced that this incentive works the same way with Ergon as it would work with a privately owned network. There is still the risk of a future ex post review as we noted above, but that is not the way incentive-based regulation is ideally supposed to work as it increases the chances of consumers paying the extra 70%.

While the CESS revisions last year pick up the asymmetric risk consumers face from underspend, it does not cover the asymmetric risk on overspend that, based on recent evidence, is more likely in Energy Queensland than other networks. This table is similar to the one above for opex – showing the forecast total capex spend for the current period at the time of the Initial proposal compared to the AER allowance[86].

2019-24	Actual/forecast spend in January 2023 compared to approved allowance for 2019-24
Ausgrid	-13%
Endeavour	-7%
Essential	-7%
2020-25	Actual/forecast spend in January 2024 compared to approved allowance for 2020-25
Energex	14%
Ergon	76%
SAPN	0%

It suggests that the drive to meet the allowance is perhaps weaker for Ergon and Energex that other networks. While we do support the application of CESS to Ergon's capex spend in 2025-30, we are not confident that it acts as the same efficiency incentive that it does for privately owned networks.

7. Operational Expenditure

7.1 Energex Operational Expenditure

<u>What is Energex Proposing?</u>

The table summarises recent history of AER allowances, actual and forecast spend in the current period and Energex's proposed spend in 2025-30.

$2024/25m	2015-20	2020-25	2025-30

[85] See p.16 https://www.aer.gov.au/system/files/AER%20-%20Final%20Framework%20and%20Approach%20%20-%20Ergon%20and%20Ergon%202025-30%20-%20June%202023_1.pdf
[86] Information provided by the AER.

	AER allowance	Actual	AER allowance	Actual/ Forecast	Forecast	% change vs 2020-25 AER allowance	% change vs 2020-25 actual/forecast
Total opex (excl debt raising)	2,263.5	2,245.7	2,234.1	2,426.0	2,245.6	+0.5%	-7.4%

Energex has adopted the AER's 'base, step, trend' approach to developing its opex forecast.

Base	• The base year of 2023-24 has been selected as a '…realistic expectation of the efficient and sustainable on-going opex that is required to provide [standard control services] over the 2025-30 regulatory control period" (p.136)
	• This has then been adjusted in a number of ways:
	  ○ Reduction of $138.9m (5.9%) 'efficiency adjustment' to reflect Energex's relative efficiency from the latest (2023) AER benchmarking results and after accounting for 'operating environment factors'
	  ○ Reduction of $13.7m/yr (total $68.2m) Electrical Safety Office levy that will be a jurisdictional scheme in 2025-30
	  ○ Reduction of $6.7m/yr (total $33.5m) relating to property leases that will be treated as capex in 2025-30
	  ○ Reduction of $12.7m to reflect the change in opex from the base year to the final year (2024-25) following the AER's Expenditure Forecast Assessment Guideline
	Removing debt raising costs of $32.4m for the existing period and added in $39.3m for 2025-30 based on the benchmark rate

Step	There is one step change of $14.6m (0.6%) relating to the acquisition, processing and use of smart meter data; there may be another relating to the cost of inspecting private property poles which will be included in the Revised Proposal
Trend	• The efficient base year is trended forward over 2025-30 to reflect changes in price outputs and productivity • The AER mandates that networks achieve at least 0.5%/yr productivity improvement in total opex (base + step + trend); Energex has proposed a 1%/yr productivity factor which means a reduction of $66m.

Energex is proposing that the Efficiency Benefit Sharing Scheme, which incentivises Energex to (p.147):

> "… continuously pursue opex efficiency improvements and share these with customers"

and which applies in the current period, continues in 2025-30. The AER's F&A indicated that the application of the EBSS will occur if the opex forecasts are based on Energex's revealed costs. The forecast opex overspend in the current period has led Energex to forecast significant negative EBSS carryovers ie penalties (p.148):

Table 63: Energex's EBSS calculation

	Future Period					
$m, real 2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	Total[1]
Forecast EBSS penalties	-68.8	-32.1	-24.0	3.1	0.0	**-121.8**

Note 1: Total may not add due to rounding.

<u>AER comments</u>

The AER noted that, based on their initial assessment, Energex's proposal meets the base, step trend approach – base year efficiency adjustments, other adjustments, 1% productivity, only one minor step change and no category specific costs apart from debt raising. It did not raise any specific issues of concern.

The AER concluded in its Framework and Approach that it[87]:

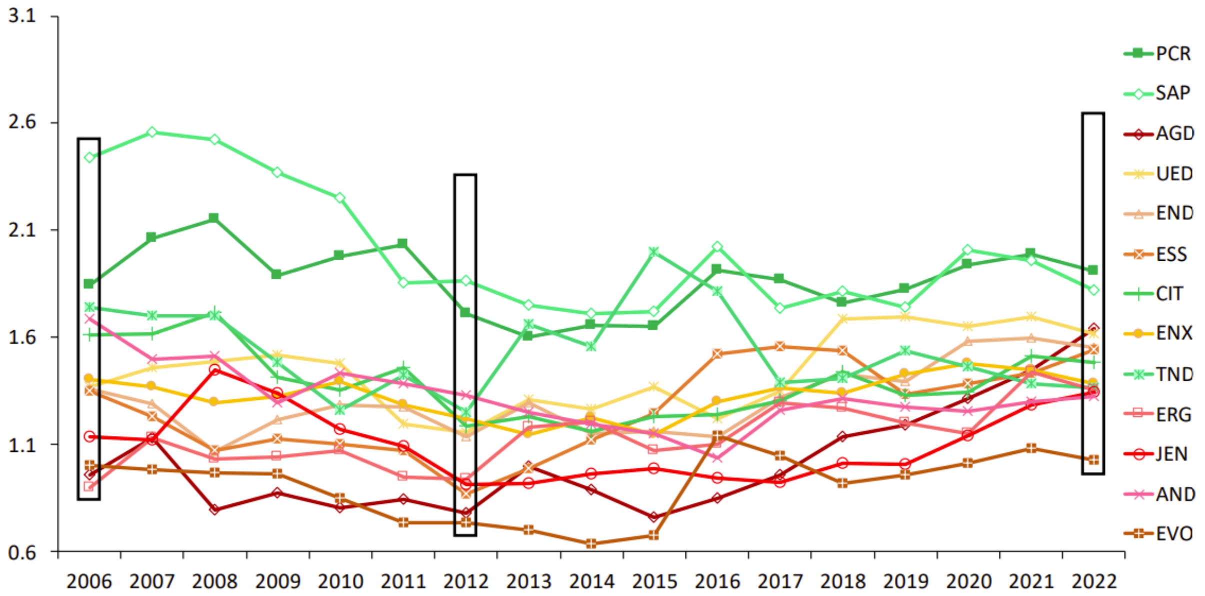
> "… intends to apply the EBSS to Energex and Energex in the 2025−30 regulatory control periods if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers. This will occur only if the opex forecasts for the following period are based on the distributors' revealed costs. Our distribution determinations for Energex and Energex for the 2025−30 regulatory control period will specify if and how we will apply the EBSS."

RRG comments

Base year opex

This starting point is to determine a 'not materially inefficient' base year (2023-24) opex. The AER draws on its annual productivity reports to make this determination. The most recent publication was in November 2023 covering 2021-22 – the final decision in 2025 will draw on the November 2024 results covering 2022-23. Over the 15 years of available benchmark data, Energex's (ENX) opex productivity performance has generally been around the middle of the 13 DNSPs but has deteriorated in the last couple of years[88].

Figure 13 DNSP opex MPFP indexes under the preferred approach to addressing capitalisation differences, 2006–2022



Energex's performance in the latest AER results for 2022 shows Energex's position continues to be generally well down the ladder (p.137):

AER methodology	Energex rank

[87] See p.16 https://www.aer.gov.au/system/files/AER%20-%20Final%20Framework%20and%20Approach%20%20-%20Energex%20and%20Energex%202025-30%20-%20June%202023_1.pdf

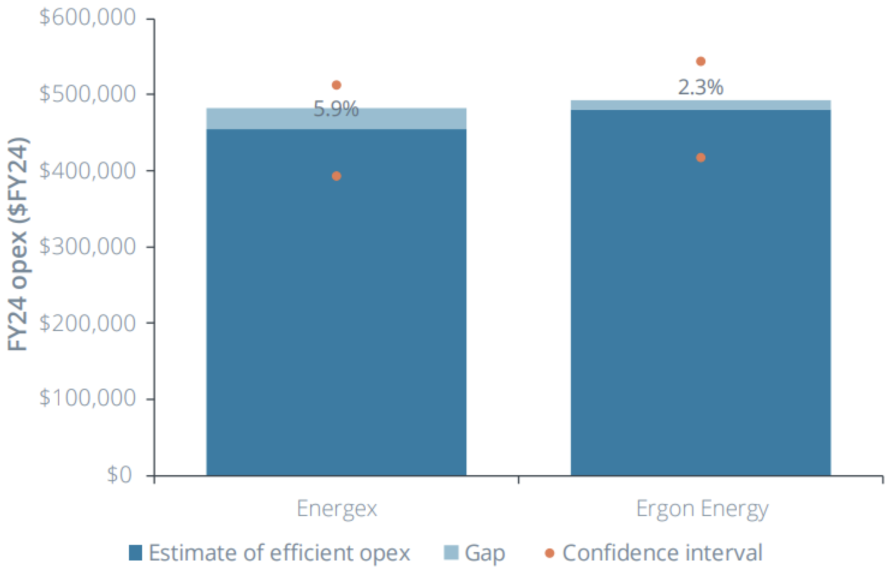
[88] See Figure 13 p.36 https://www.aer.gov.au/system/files/2023-11/2023%20Annual%20Benchmarking%20Report%20%E2%80%93%20Electricity%20distribution%20network%20service%20providers%20%E2%80%93%20November%202023.pdf

Multilateral total factor	9th
Econometric (long sample)[1]	11th
Econometric (short sample)[1]	8th

1. Including capitalisation differences

There is a perennial debate between networks and the AER on the usefulness and accuracy of the AER benchmarking data. Energex provides the usual consultant's report from Frontier[89] that goes though the familiar arguments around why the AER's benchmarking methodology is flawed eg the AER's approach of comparing actual base year opex to an estimate of the efficient base year for assessing material inefficiency fails to take account of the statistical uncertainty of the latter's measurement. Applying Frontier's confidence intervals around the 'efficiency' benchmark cost suggests that the base year for Energex, adjusted for 'operating environment factors' (OEFs)[90] means Energex is 'not materially inefficient' and hence no adjustment would be required[91].

Figure 1: Estimates of efficient base year opex ($FY2024)



Nevertheless, the AER's approach means they will apply an adjustment. In anticipation of this certainty, Energex, using results from the Frontier study, has proposed a reduction of $138.9m (5.9%) in the 2023-24 revealed base year cost. Energex described the efficiency adjustment (p.141):

> "While we consider that an efficiency adjustment is not required in light of the material concerns that we have with the AER's benchmarking model, we have incorporated the efficiency adjustment to further address affordability concerns."

We leave the AER to assess whether this is the appropriate adjustment. If the AER's alternative estimate is higher than the Energex proposal then the AER will accept the Energex base year number.

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[89] https://www.aer.gov.au/system/files/2024-02/Energex%20-%206.04%20-%20Frontier%20Economics%20-%20Opex%20benchmarking%20report%20-%20January%202024.pdf

[90] For a discussion see https://www.aer.gov.au/industry/registers/resources/reviews/review-operating-environment-factors-distribution-network-service-providers

[91] See p.5 https://www.aer.gov.au/system/files/2024-02/Energex%20-%206.04%20-%20Frontier%20Economics%20-%20Opex%20benchmarking%20report%20-%20January%202024.pdf

If the AER's alternative estimate is lower that the Energex proposal, the AER will substitute its alternative base year estimate.

While Energex and Frontier may complain about the AER's methodology overestimating the adjustment they may be required to make, they make no mention of another aspect of the 'not materially inefficient' methodology that suggests a potentially large underestimate of the downward adjustment.

A reasonable starting point for assessing the relative inefficiency of a regulated network, where the aim is to replicate a workably competitive market, would be to adjust the base year costs of all networks that are below the most efficient network on the 'frontier' (adjusted for OEFs). That is what would be expected over time in a competitive market – firms adjust to the frontier (which may be constantly 'moving out') and if they do not, they go out of business as new entrants come in with lower costs. This approach was rejected by the AER which pointed to the incentive regulatory framework and reliance on revealed costs as networks respond to the incentives. It seems the AER believes that the incentive framework will, over time, mean all networks gradually get to the efficiency level of the frontier firm.

Yet it can take time for a network to respond to the EBSS incentive and, in the meantime, consumers are paying for that inefficiency. As the above figure shows, while there has been some narrowing of the range of opex productivity levels, there is still some distance from the best (which are not improving) to the worst. The longer the adjustment, the more consumers pay for a network's inefficiency as it goes on the long and winding road to the frontier.

The other argument the AER advanced – no doubt influenced by the legal arguments around how precise a benchmark can be in defining the 'efficient' level (what Frontier and Energex are arguing with their confidence band argument) - is the AER's Expenditure Forecast Assessment Guideline approach which adjusts revealed opex when the AER's analysis demonstrates it is *materially* inefficient[92].

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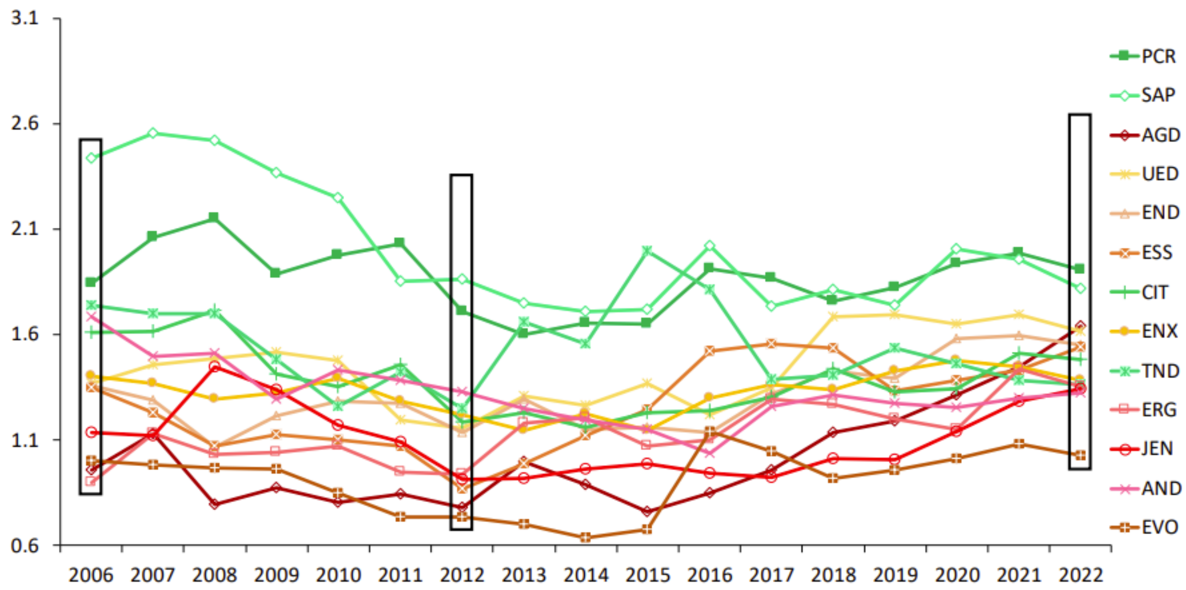
Figure 13 DNSP opex MPFP indexes under the preferred approach to addressing capitalisation differences, 2006–2022



The AER went on to say[97]:

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[96] See Fig 13 p.36 https://www.aer.gov.au/system/files/2023-11/2023%20Annual%20Benchmarking%20Report%20%E2%80%93%20Electricity%20distribution%20network%20service%20providers%20%E2%80%93%20November%202023.pdf

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survive in the long term being 20-25% less efficient than the most efficient firm in the particular industry.

The AER is going to make the adjustment anyway irrespective of Energex's view of the benchmarking methodology. This adjustment is going to be made on the basis of a very generous (to Energex) view of network efficiency. While reducing inefficient costs to address affordability concerns is required, the much better outcome for consumers would have been for Energex to be efficient (even under the AER's generous definition) in the first place. Under the EBSS scheme consumers have borne 70% of the costs of that inefficiency – forecast to be an additional $134.3m costs to consumers over the current regulatory period 2020-25[98].

We understand the AER's work programme includes a review of the 0.75 benchmark in the next couple of years. Not a moment too soon.

Step changes

There was considerable uncertainty over the likely cost following the AEMC's review of metering services[99]. Clarification of that decision's impact eg basic power quality data should be provided free of charge, contributed to a significant fall in estimated costs from $52.8m in the Draft Plan to $14.6m in this Proposal.

Energy Queensland engaged in some detail with the RRG on the smart data step change. This included various options on the level and timeliness of data that would be purchased with a focus on the highest cost-benefit option without bias for technology or timing of costs. We support the Proposal's data acquisition eg near real time data for 20% of available smart meters and leave it to the AER to assess the prudency and efficiency of the proposed expenditure.

It is pleasing to see that Energex responded to our submission on the Draft Plan questioning whether the other two step changes on cyber security ($5.0m) and increase insurance premiums ($5.5m) fit the materiality definition. Energex regards them as immaterial and is absorbing those costs in the normal opex allowance to improve affordability.

Trend

Price and output growth are subject to standard AER methodologies.

Energex is proposing a 1% annual productivity factor when it is only required to have 0.5% per year. This higher productivity factor reduces forecast opex by an additional $34.4m over the required 0.5% - representing 1.6% of total opex. While we do congratulate Energex for this affordability initiative, as we noted in our submission on the Draft Plan and commented on above, we consider this to be a stretch target. Forecast opex for the current 2020-25 period is 8.6% above the AER allowance and Energy Queensland emphasised to the RRG the cost pressures it is currently facing and which are expected to continue for some years. At least consumers will only pay 70% of any overrun rather than 100% of the overrun were Energex to only propose the minimum 0.5% annual productivity.

EBSS

Under the incentive regulatory framework, incentive schemes are designed encourage Energex to (p.144):

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[98] This is 70% of the combined overspend in 2015-20 and 2020-25.
[99] https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

> "…run efficient businesses so that customers pay no more than is necessary for the services they require and ensure the right levels of service are delivered to customers."

While Energex is proposing that EBSS apply in 2025-30 (see pp 147-8) the AER's F&A indicates that the application of EBSS is conditional on the application of the revealed cost forecasting approach. We are not convinced that this should be the only criterion.

Energex initial proposed opex for the current 2020-25 period was accepted by the AER in its Draft Decision because it was lower than the AER's alternative estimate of efficient opex. Energex accepted the Draft Decision[100]:

> "Even though our updated internal opex forecasts were higher than our January proposals, in line with stakeholder feedback, we have accepted the Draft Decision opex allowance and limited our revised opex for both Energex and Energex Energy."

Given this, the EBSS applied. Yet opex expenditure has significantly exceeded the AER allowance leading to a $121.8m EBSS penalty in 2025-30. Current period forecast expenditure is 8.6% above allowance. Energex has followed the revealed cost forecasting approach but we consider consumers face an asymmetric risk. In the discussions with the RRG, Energy Queensland has repeatedly referred to the current large cost pressures for labour and materials that are expected to continue over 2025-30.

While Energex have based their opex forecast on revealed costs, a combination of Energex's recent historical performance against allowance plus Energex's indications of future cost pressures combine to suggest the AER's 2025-30 opex allowance may be difficult to meet. Data for current and most recent period opex spend by DNSPs suggests that Ergon and Energex, along with Essential are less likely to be able to meet AER opex allowances. The table shows the comparison between the network's forecast opex for the relevant current period compared with the AER allowance for that period[101].

	2019-24		
	Approved allowance ($m)	Actual/forecast spend by network in January 2023 ($m)	Difference %
Ausgrid	2,806.6	2,157.5	-23.5%
Endeavour	1,754.3	1,375.3	-21.6%
Essential	2,115.9	2,282.4	7.9%
	2020-25		
	Approved allowance ($m)	Actual/forecast spend by network in January 2024 ($m)	Difference %
Energex	2,272.8	2,448.7	7.7%
Ergon	2,290.2	2,374.5	3.7%
SAPN	1,779.4	1,666.8	-6.3%

While Energex will share 30% of the cost overrun, this incentive may not work the same way with Energex as it would work with other networks listed in the table. Unlike capex, there is no ex-post

[100] See p.21 https://www.aer.gov.au/system/files/Energex%20Energy%20-%20Revised%20Proposal%20-%201.001%20-%20Overview%20-%20Revised%20Regulatory%20Proposals%202020-25%20-%20December%202019.pdf
[101] Information provided by the AER to ensure comparability.

review so 70% of the opex overrun is paid for by consumers irrespective of whether it is efficient and prudent. While we agree with the Energex quote above on the need to run efficient businesses, we are not confident that this occurs in practice. The focus for all customers should be on network efficiency, not network inefficiency compensated by a Government subsidy to some, but not all, customers.

While we support the application of EBSS in 2025-30, we simply highlight the fact that C&I customers are far more exposed to inefficient expenditure than residential or small business.

7.2 Ergon Operational Expenditure

<u>What is Ergon proposing?</u>

The table summarises recent history of AER allowances, actual and forecast spend in the current period and Ergon's proposed spend in 2025-30.

$2024/25m	2015-20		2020-25		2025-30		
	AER allowance	Actual	AER allowance	Actual/ Forecast	Forecast	% change vs 2020-25 AER allowance	% change vs 2020-25 actual/forecast
Total opex (excl debt raising)	2301.3	2,464.9	2,254.7	2,349.5	2,336.0	+3.6%	0.1%

Ergon has adopted the AER's 'base, step, trend' approach to developing its opex forecast.

Base	• The base year of 2023-24 has been selected as a '…realistic expectation of the efficient and sustainable on-going opex that is required to provide [standard control services] over the 2025-30 regulatory control period" (p.136)
	• This has then been adjusted in a number of ways:
	    ○ Reduction of $55.3m (2.3%) 'efficiency adjustment' to reflect Ergon's relative efficiency from the latest (2023) AER benchmarking results and after accounting for 'operating environment factors'
	    ○ Reduction of $7.7m/yr (total $38.5m) Electrical Safety Office levy that will be a jurisdictional scheme in 2025-30
	    ○ Reduction of $5.9m/yr (total $29.5m) relating to property leases that will be treated as capex in 2025-30
	    ○ Reduction of $30.7m to reflect the change in opex from the base year to the final year (2024-25) following the AER's Expenditure Forecast Assessment Guideline
	Removing debt raising costs of $30.4m for the existing period and added in $43.1m for 2025-30 based on the benchmark rate

Step	There is one step change of $6.8m (0.3%) relating to the acquisition, processing and use of smart meter data; there may be another relating to the cost of inspecting private property poles which will be included in the Revised Proposal
Trend	• The efficient base year is trended forward over 2025-30 to reflect changes in price outputs and productivity • The AER mandates that networks achieve at least 0.5%/yr productivity improvement in total opex (base + step + trend); Ergon has proposed a 1%/yr productivity factor which means a reduction of $63m.

Ergon is proposing that the Efficiency Benefit Sharing Scheme, which incentivises Ergon to (p.148):

> "… continuously pursue opex efficiency improvements and share these with customers"

and which applies in the current period, continues in 2025-30. The AER's F&A indicated that the application of the EBSS will occur if the opex forecasts are based on Ergon's revealed costs. The forecast opex overspend in the current period has led Ergon to forecast significant negative EBSS carryovers ie penalties (p.149):

Table 61: Ergon Energy Network's EBSS calculation

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

Note 1: Total may not add due to rounding.

<u>AER comments</u>

The AER noted that, based on their initial assessment, Ergon's proposal meets the base, step trend approach – base year efficiency adjustments, other adjustments, 1% productivity, only one minor step change and no category specific costs apart from debt raising. It did not raise any specific issues of concern.

The AER concluded in its Framework and Approach that it[102]:

> "… intends to apply the EBSS to Ergon and Energex in the 2025−30 regulatory control periods if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers. This will occur only if the opex forecasts for the following period are based on the distributors' revealed costs. Our distribution determinations for Ergon and Energex for the 2025−30 regulatory control period will specify if and how we will apply the EBSS."

<u>RRG comments</u>

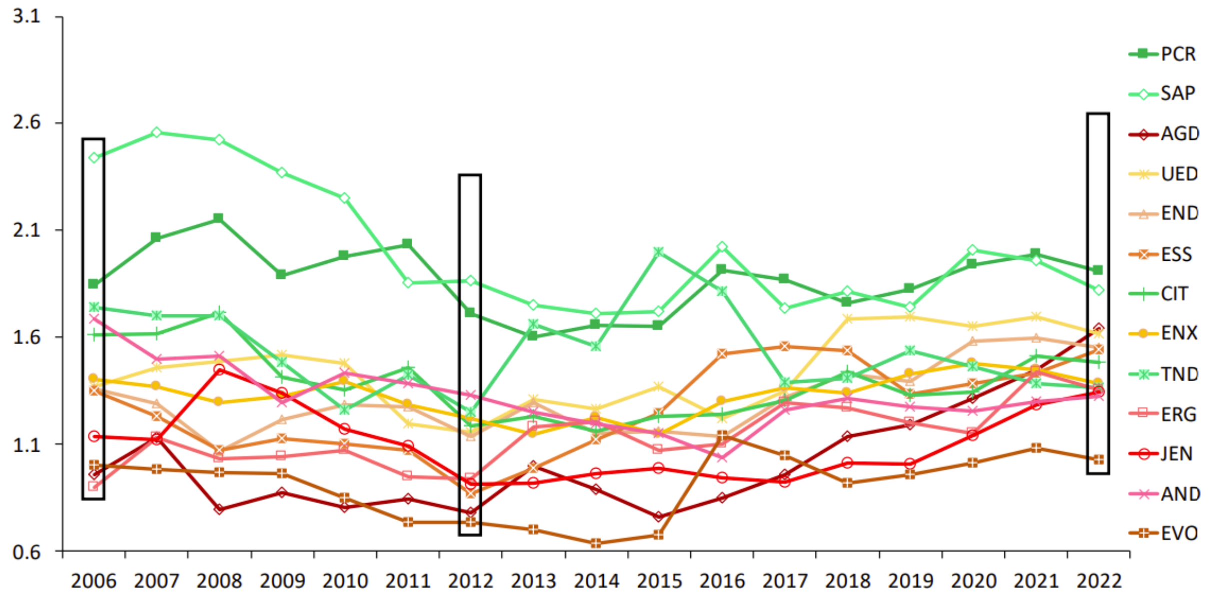
Base year opex

This starting point is to determine a 'not materially inefficient' base year (2023-24) opex. The AER draws on its annual productivity reports to make this determination. The most recent publication was in November 2023 covering 2021-22 – the final decision in 2025 will draw on the November 2024 results covering 2022-23. Over the 15 years of available benchmark data, Ergon's (ERG) opex productivity performance has generally been in the bottom half of the 13 DNSPs[103].

[102] See p.16 https://www.aer.gov.au/system/files/AER%20-%20Final%20Framework%20and%20Approach%20%20-%20Ergon%20and%20Energex%202025-30%20-%20June%202023_1.pdf

[103] See Figure 13 p.36 https://www.aer.gov.au/system/files/2023-11/2023%20Annual%20Benchmarking%20Report%20%E2%80%93%20Electricity%20distribution%20network%20service%20providers%20%E2%80%93%20November%202023.pdf

Figure 13 DNSP opex MPFP indexes under the preferred approach to addressing capitalisation differences, 2006–2022



Ergon's performance in the latest AER results for 2022 shows Ergon's position continues to be generally well down the ladder (p.137):

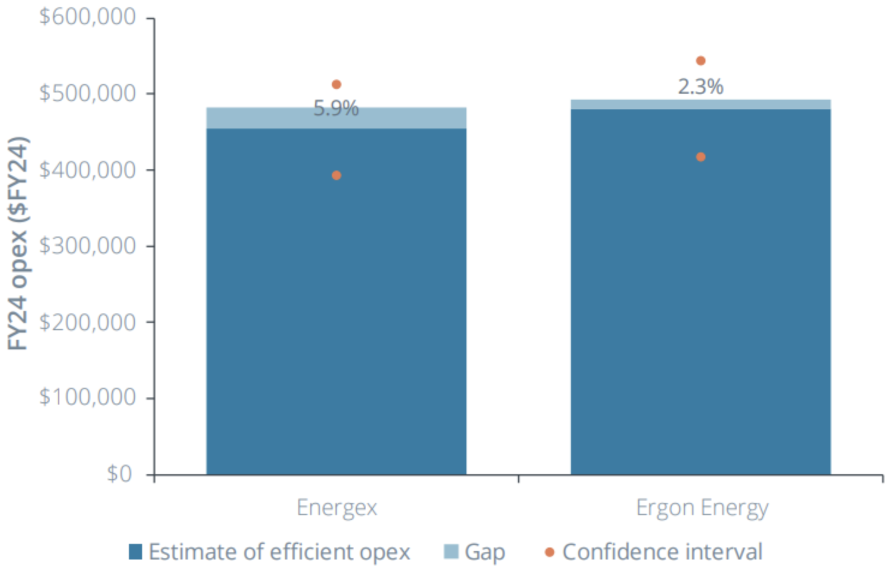
AER methodology	Ergon rank
Multilateral total factor	6th
Econometric (long sample)[1]	11th
Econometric (short sample)[1]	11th

1. Including capitalisation differences

There is a perennial debate between networks and the AER on the usefulness and accuracy of the AER benchmarking data. Ergon provides the usual consultant's report from Frontier[104] that goes though the familiar arguments around why the AER's benchmarking methodology is flawed eg the AER's approach of comparing actual base year opex to an estimate of the efficient base year for assessing material inefficiency fails to take account of the statistical uncertainty of the latter's measurement. Applying Frontier's confidence intervals around the 'efficiency' benchmark cost suggests that the base year for Ergon, adjusted for 'operating environment factors' (OEFs)[105] means Ergon is 'not materially inefficient' and hence no adjustment would be required[106].

[104] https://www.aer.gov.au/system/files/2024-02/Ergon%20-%206.04%20-%20Frontier%20Economics%20-%20Opex%20benchmarking%20report%20-%20January%202024%20-%20public.pdf
[105] For a discussion see https://www.aer.gov.au/industry/registers/resources/reviews/review-operating-environment-factors-distribution-network-service-providers
[106] See p.5 https://www.aer.gov.au/system/files/2024-02/Energex%20-%206.04%20-%20Frontier%20Economics%20-%20Opex%20benchmarking%20report%20-%20January%202024.pdf

Figure 1: Estimates of efficient base year opex ($FY2024)



Nevertheless, the AER's approach means they will apply an adjustment. In anticipation of this certainty, Ergon, using results from the Frontier study, have proposed a reduction of $55.3m (2.6%) in the 2023-24 revealed base year cost. Ergon has described the efficiency adjustment (p.141):

> "While we consider that an efficiency adjustment is not required in light of the material concerns that we have with the AER's benchmarking model, we have incorporated the efficiency adjustment to further address affordability concerns."

We leave the AER to assess whether this is the appropriate adjustment. If the AER's alternative estimate is higher than the Ergon proposal then the AER will accept the Ergon base year number. If the AER's alternative estimate is lower that the Ergon proposal, the AER will substitute its alternative base year estimate.

While Ergon and Frontier may complain about the AER's methodology overestimating the adjustment they may be required to make, they make no mention of another aspect of the 'not materially inefficient' methodology that suggests a potentially large underestimate of the downward adjustment.

A reasonable starting point for assessing the relative inefficiency of a regulated network, where the aim is to replicate a workably competitive market, would be to adjust the base year costs of all networks that are below the most efficient network on the 'frontier' (adjusted for OEFs). That is what would be expected over time in a competitive market – firms adjust to the frontier (which may be constantly 'moving out') and if they do not, they go out of business as new entrants come in with lower costs. This approach was rejected by the AER which pointed to the incentive regulatory framework and reliance on revealed costs as networks respond to the incentives. It seems the AER believes that the incentive framework will, over time, mean all networks gradually get to the efficiency level of the frontier firm.

Yet it can take time for a network to respond to the EBSS incentive and, in the meantime, consumers are paying for that inefficiency. As the above figure shows, while there has been some narrowing of the range of opex productivity levels, there is still some distance from the best (which are not improving) to the worst. The longer the adjustment, the more consumers pay for a network's inefficiency as it goes on the long and winding road to the frontier.

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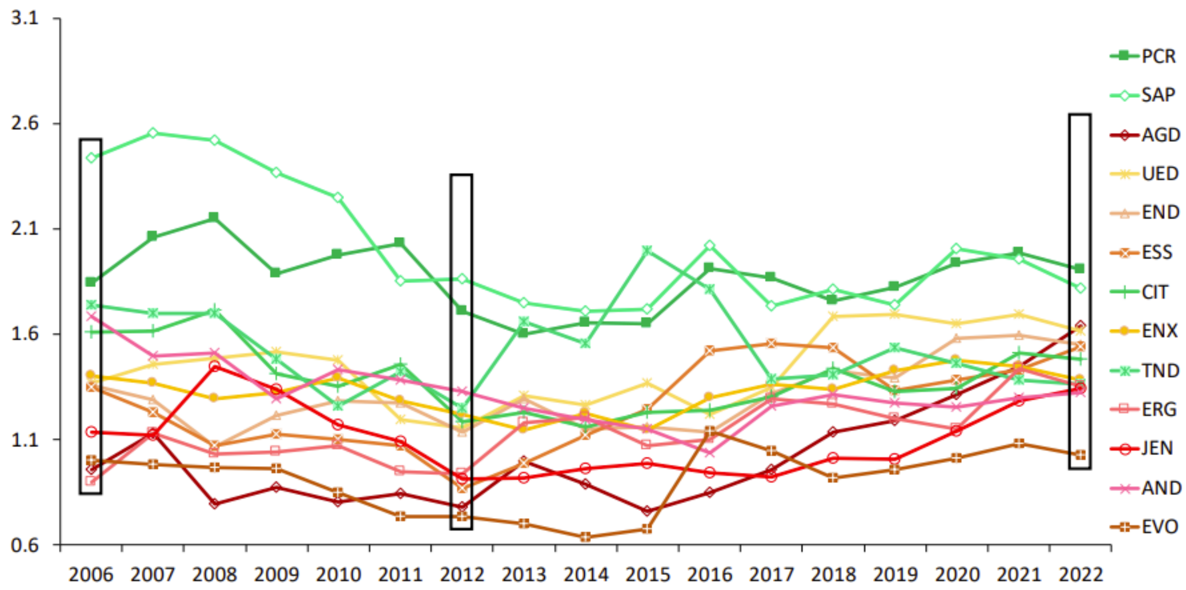

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Given this, the EBSS applied. Yet opex expenditure has significantly exceeded the AER allowance leading to a $199m EBSS penalty in 2025-30. Current period forecast expenditure is 3.6% above allowance. Ergon has followed the revealed cost forecasting approach but we consider consumers face an asymmetric risk. In the discussions with the RRG, Energy Queensland has repeatedly referred to the current large cost pressures for labour and materials that are expected to continue over 2025-30.

While Ergon have based their opex forecast on revealed costs, a combination of Ergon's recent historical performance against allowance plus Ergon's indications of future cost pressures combine to suggest the AER 2025-30 opex allowance may be difficult to meet. Data for current and most recent period opex spend by DNSPs suggests there may be a stronger incentive on privately owned networks to respond to EBSS and seek to reduce costs below the allowance. The table shows the comparison between the network's forecast opex for the relevant current period compared with the AER allowance for that period[116].

	2019-24		
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[115] See p.21 https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Revised%20Proposal%20-%201.001%20-%20Overview%20-%20Revised%20Regulatory%20Proposals%202020-25%20-%20December%202019.pdf

[116] Information provided by the AER to ensure comparability.

uniform tariff policy which will shield them to the extent that the Energex opex overspend is less than Ergon's. Then there are Government electricity rebates that further cushion any impact.

However, C&I customers do not benefit from the uniform tariff policy and do not receive any Government rebate. They must bear the full cost of an inefficient opex overspend. While we agree with the Ergon quote above on the need to run efficient businesses, we are not confident that this occurs in practice. The focus for all customers should be on network efficiency, not network inefficiency compensated by a Government subsidy to some, but not all, customers.

While we support the application of EBSS in 2025-30, we simply highlight the fact that C&I customers are far more exposed to inefficient expenditure than residential or small business.

8. Incentive Schemes

What are Energex and Ergon proposing?

The incentive schemes that Energex and Ergon are proposing should apply in the 2025-30 regulatory control period are STPIS, EBSS, CESS, DMIA and DMIAM, consistent with the schemes that apply in the current regulatory period[117].

Energex and Ergon are not proposing to introduce the new CSIS and ESIS schemes. Energex and Ergon explored potential introduction of the new CSIS scheme through the Voice of Customer (VoC) engagement process. During this process, Energex and Ergon received strong feedback from customers that while good customer service is important for customers, it should not be incentivised for their businesses ie customers are not willing to pay for improved customer service that should occur without specific payment. Based on this feedback, Energex and Ergon are not only proposing not to apply the CSIS, but they are also proposing to remove application of the STPIS customer service component (telephone answering), and the related 0.2% revenue at risk which is part of the current STPIS framework[118].

AER Comments

The AER may determine whether or not to apply the STPIS telephone answering parameter during a regulatory control period[119]. In relation to application of a CSIS, the AER Issues Paper explains that[120]:

> "…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."

Furthermore, the AER note[121]:

> "If neither scheme applies, then it may be astute to track a range of metrics over the period to improve transparency."

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[117] See p.145, https://www.aer.gov.au/system/files/2024-02/Ergon%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public_0.pdf
[118] See p.150, https://www.aer.gov.au/system/files/2024-02/Ergon%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public_0.pdf
[119] See p.44, https://www.aer.gov.au/system/files/2024-04/AER%20-%20Issues%20Paper%20-%20Energy%20Queensland%20-%202025-30%20Dx%20Determination%20-%20March%202024_0.pdf
[120] Ibid
[121] Ibid

RRG Comments

To our knowledge, the proposal put forward by Energex and Ergon to apply neither the CSIS nor the telephone answering component of STPIS has not been advanced or adopted by any other DNSP since introduction of the new CSIS. However, the RRG consider that it accurately reflects the sentiments expressed by customers who were engaged on this matter.

In our response to the Energex and Ergon Draft Plans the RRG observed that the VoC process clearly indicated a preference for no incentive scheme. We also noted that to be consistent with the views expressed by the VoC, Energex and Ergon should not continue with the current telephone answering measure which includes the option of an incentive payment.

The RRG considered the possible risks to customers associated with removal of all customer service incentive schemes. In their advice to Energex and Ergon, VoC participants highlighted an ongoing need for accountability and transparency by recommending that the businesses' customer service performance should be monitored by the regulator and/or the ombudsman.

In response to the question in the Draft Plans *"Do you support our proposal to publish regular reports on our customer service performance?"* the RRG recommended further engagement with customers to clarify:

- the scope, purpose and frequency of reporting
- the audience
- performance metrics to be reported
- integration with existing reporting obligations eg. GSL reporting, Energy Charter reporting, Annual Report etc.
- the additional cost to customers.

RRG considers that in the absence of both customer service incentive schemes it is essential that a replacement reporting framework including governance arrangements, together with relevant performance metrics and targets is developed and implemented in collaboration with customers. Engagement on this framework needs to be broader than the residential customer cohort that were engaged through the VoC process. Energex and Ergon state that they[122]:

> "commit to work with our customers and stakeholders to develop agreed customer service performance reporting throughout the period".

The RRG believes that this framework must be developed in time for it to be included as part of the Revised Regulatory Proposal to give customers and the AER confidence that a strong focus on good customer service will be maintained in the future.

9. Tariff Structure Statements

What are Energex and Ergon proposing?

Energex and Ergon confirmed that they will continue with the current control mechanism – revenue cap for standard control services and price cap for alternative control services.

[122] See p.153, https://www.aer.gov.au/system/files/2024-02/Ergon%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public_0.pdf

For both networks the focus of the TSSs is (Energex p.171):

> "In response to customer feedback, we are proposing changes to our network tariffs and assignment arrangements by strengthening the peak price signal, updating ToU pricing windows, transitioning to two-way pricing to support renewables, updating controlled load tariffs, and streamlining existing tariffs."

It is expected that these changes will send efficient signals to customers (assuming retailers pass them on) that will lead to more efficient use of the network throughout the day and ensure a more efficient signal to future investment.

AER comments

The Issues Paper provides a high-level assessment of the TSS against the Better Resets expectations. The results were mixed. The progress on providing increasing cost reflective tariffs and tariff streamlining were favourably commented on.

RRG comments

Our comments focus on standard control services. As we noted in our Engagement submissions, consultation of tariff structures was an important part of overall engagement. At a general level, the RRG:

- strongly supports the move towards more cost reflective pricing and the reduction in existing cross subsidies
- believes that the role of network pricing is to achieve efficiency objectives and not to achieve social equity objectives which is the role of Government concessions and rebates
- does not support technology specific tariffs that involve a cross subsidy to support a business case for a new technology eg special EV or storage tariffs; if Governments consider development of these technologies should be supported then that should be through explicit Government support, not cross subsidisation from other network customers.

Specifically, the RRG supports:

- the proposed replacement of existing default tariffs for residential and small business with new TOU demand and energy tariffs
- the long-term plans to move to demand or capacity charge only and no longer offer energy only tariffs
- the proposed two-way tariff including a 'free' basic export level and an export transition strategy
- dynamic connection agreements
- the proposed tariffs for EV charging stations - our concern is that even though the EV industry may claim its proposal to opt out of demand tariffs up to a 160MWh threshold is warranted, this locks in a cross-subsidy tariff that will be hard to change in the future; we support a cost reflective tariff that provides incentives to charge outside of peak times
- the proposed tariffs to apply to batteries – again we do not see the role of the network tariffs to subsidise a business case for batteries.

As an example of the last point, we were presented with the submission of Zero Emission Noosa, a not-for-profit seeking to develop a community battery in Noosa. A partnership between Noosa Council, Zero Emissions Noosa Inc (ZEN Inc), and Yarra Energy Foundation (YEF) was successful in obtaining a grant to install a community battery in Noosaville under the Federal Government's

Community Batteries for Household Solar Program Stream[123]. They plan to sell the entire capacity of the battery to a community retailer who will then market the power to local residents. So the operating costs – with the major one being network tariffs – have to be covered by the revenue from the retailer. The business case in their application was based on a Citipower community battery tariff given there was no Energex tariff available. This resulted in a forecast net income that was going to be used to fund emission reduction projects in the Noosa shire.

However, the proposed Energex tariff is higher than the Citipower tariff (Noosa Council claims it is the highest storage tariff in Australia) and the project business case shows an annual loss of ~$8,000. We have no information on what process was used to arrive at the agreed selling price to the retailer but it seems that the required network tariff is a goal seek to ensure there is no loss on the transaction with the retailer. As one of the Noosa Battery submissions noted[124]:

> "Community batteries tariffs must establish and build positive business cases for rapid and far-reaching battery storage and network firming implementation …
>
> An urgent focus on tariffs is required to a build better business case for local storage."

The RRG definitely agrees with the arguments on the role of batteries to support the energy transition. However, we do not think the developers of community batteries should expect other Energex or Ergon consumers to cross subsidise to support their business case.

While tariffs were an important part of the consumer engagement pre-lodgement, we consider there is scope for further work as the original consultation designed to feed into the TSS did not provide sufficient time or information for participants to generate the detailed feedback Energy Queensland needed to fully understand and integrate consumer views and preferences.

In recognition of the limitations of the original consultation, Energy Queensland has established an expanded and ongoing Network Pricing Working Group (NPWG) to focus on 2025-30 tariffs including responding to submissions on the TSS. This working group consists of a diverse set of participants representing interest in both the Ergon and Energex network areas. It also includes representation ranging from large industrial consumers, agricultural and regional consumers, small business, energy retailer and residential customers. It includes all members of the RRG. With external facilitation by Mosaic LAB, the NPWG has developed formal terms of reference and agreed methods of working together. It has also an established ongoing work program and we believe that this will provide additional breadth and depth and an overall richness to the development of the ongoing tariff conversation.

Topics discussed in the NPWG include load control, dynamic connections, tariffs for customers with annual demand between 100-160MWh (eg public EV charging facilities) and storage tariffs (eg Noosa Council community battery). Another key issue is the tariff impacts on larger customers in both Ergon and Energex, but particularly in Ergon where they do not have the benefit of the Uniform Tariff Policy nor receive any Government rebate. This was discussed in Section 4. Much more engagement is required for these customers on the inevitable bill shock they will experience every year in 2025-30 were the January 2024 proposals to be accepted by the AER.

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[123] See p.1 https://www.aer.gov.au/system/files/2024-05/Noosa%20Council%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex%20-%20May%202024.pdf

[124] See p.1 https://www.aer.gov.au/system/files/2024-05/Zero%20Emissions%204075%20Inc%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex%20%26%20Ergon%20-%20May%202024.pdf

The RRG recognise the value in providing solar customers with a choice between a dynamic connection and incurring charges for solar export, and also understand the role of dynamic connections in improving network utilisation. However, we are unclear about the interrelationships between sun soaker tariffs, two-way charging and dynamic connections. We question whether the cost allocations between different customer cohorts is asymmetric, particularly the cost allocations between solar and non-solar customers over time. We consider than more information is required to assure customers, non-solar customers in particular, that the existing cross subsidy between non-solar and solar customers is not being preserved through the implementation of dynamic connections.

We believe that demand and energy tariffs as the default tariff structure for residential and small business customers do balance the pace of reform with customer views/impacts. While Energy Queensland has undertaken limited consultation generally around the broader regulatory reset, there were genuine attempts to consult with consumers around the future focused energy tariffs. In the consultations it was generally agreed that consumers were interested in a medium pace of transition to new tariffs. As such the transitional arrangements proposed by Energy Queensland are in line with consumer expectations.

The tariff reform (demand tariffs) along with dynamic connections also was developed with consumer preferences in mind to meet future uptake of PV vehicle to grid and battery storage.

10. Metering

What are Energex and Ergon proposing?

Ergon and Energex have proposed that legacy metering services currently classified as Alternative Control Services (ACS - which means they are separately charged for) should be reclassified as a Standard Control Services (SCS – which means they are recovered from all customers through the revenue cap) [125]. This change would also apply to the Mt Isa-Cloncurry network. The reclassification is justified on the basis that spreading the recovery of legacy metering costs to all customers would prevent the burden of those costs falling on a smaller cohort of customers who may face some type of difficulty in the transition to 100 per cent update of smart meters.

AER comments

In the F&A, the AER classified legacy metering as ACS. Subsequently, following publication by the AEMC of its final report on metering services, the AER is now supportive of legacy metering being classified as SCS and this is reflected in recent decisions in the ACT, NSW and Tasmania. This support extends to the Mount Isa- Cloncurry network.

RRG comments

As outlined in our Engagement Reports, Ergon and Energex conducted pre-lodgement engagement with customers on this issue. During these sessions customers were provided with clear and detailed information, including bill impact information. Based on this information, customers indicated a clear preference to support the proposed change in for allocation of costs for legacy metering services as it provides fair and equitable charging arrangements for all customers.

[125] See p.153, https://www.aer.gov.au/system/files/2024-02/Ergon%20-%202025-30%20Regulatory%20Proposal%20-%20January%202024%20-%20public_0.pdf

The RRG supports the concept of the proposed change in charging arrangements for legacy metering services as it seeks to provide fair and equitable charging arrangements for customers, whilst supporting the objectives of the AEMC and the Queensland Government in achieving 100% smart meter deployment in Queensland by 2030.

Whilst the Mount Isa-Cloncurry network is not connected to the national grid and hence AEMC metering reforms do not apply in the area, we expect customers on this network would be unaware of this regulation and would view Ergon Energy as the distributor providing their DNSP services. Even though no specific customer engagement was undertaken on this issue, the RRG agrees that exempting customers from the AEMC reforms to create specific and different treatment would be burdensome, as well as potentially delaying or preventing the benefits of smart meters in this network.

11. Ancillary Network Services

What are Ergon and Energex proposing?

Ergon and Energex are proposing consolidation of their fee-based services including discontinuing the Anytime service, some after-hours services and amalgamating the two feeder type permutations (Urban/Short Rural and Long Rural/Isolated) and introducing new services. The overall impact is to reduce Ergon's fee-based service from 310 to 137 and Energex's fee-based services from 142 to 115.

There are also increases in benchmark labour rates and fee-based services.

AER comments

These are services provided to individual customers on request and are charged on a fee or quotation basis. The costs are regulated by a price cap. The AER assesses proposed labour rates against a benchmark using a bottom-up cost build across six cost categories. Preliminary analysis against the AER's preliminary maximum efficient benchmark rates suggests some are lower but Energex's proposed labour rates for quoted services are higher. The large increase in the cost of fee-based services will be benchmarked against other networks.

RRG comments

The RRG was not involved in the engagement on these matters and so we have no comments.

12. Public Lighting

What are Ergon and Energex proposing?

The networks' proposals were the result of a detailed engagement process with stakeholders. Following the publication and presentation of the Public Lighting Issues Paper in July 2023, customer feedback was sought on the five key issues: customers' preferences for the pace of the LED deployment, funding options to support the proposed strategy, the proposed changes to the public lighting tariffs, recovery of the residual value of the legacy public lighting assets, and options for the deployment of smart control devices.

The issues were presented in terms of five statements on pages 23-25 of the Public Lighting Issues Paper, with customers invited to provide written responses to each statement by 25 July 2023. From the total base of 69 Ergon customers, there were 8 submissions (11.5%) received and from the 13 Energex customers, there were 4 submissions (30%) received.

Feedback was communicated to customers during workshops held on August 9 2023 (Ergon) and August 10 2023 (Energex) where responses and proposed actions to address the feedback were presented. The results and responses communicated were:

- Statement 1: Unanimous support for the Accelerated (100%) deployment of LEDs by 2030.
- Statement 2: Unanimous support for retaining the current suite of tariffs until 2030, the current suite of tariffs will be retained except for proposed changes to Rate 4.
- Statement 3: Overwhelming majority of support to avoid bill shock and mitigate the cost of recovering the residual value of Conventional lights. 'In principle' support from some with a requirement of further forecasts of the residual value that would be carried over beyond the regulatory period 2025-2030. Ergon and Energex proposed to provide financial forecasts of the residual value that would be carried over beyond the regulatory period 2025-2030 and how this will affect tariffs.
- Statement 4: Overwhelming majority of support for Ergon and Energex to fund replacement of Rate 2 conventional assets. Some feedback indicated customers would like to retain the option to initiate their own LED upgrade projects. Some feedback expressed concern on the proposed increase to the Rate 2 LED tariff being applied to existing LED Rate 2 assets. In response, Ergon and Energex proposed to retain the current suite of tariffs except for proposed changes to Rate 4, whereby Tariff Rate 4 would be retired and repurposed with existing assets transferred to Rate 2 LED. Tariff Rate 2A will be created and will be applied to Rate 2 assets where Ergon or Energex has funded the upgrade of the luminaire to LED. Customer initiated Rate 1 LED upgrades will be assigned to the Rate 2 LED tariff.
- Statement 5: Overwhelming majority of support for Option 1, with customers expressing preferences for the option to utilise smart controls as a user pays system, utilise on an as-needs basis, and adopt a delayed approach due to the current regulatory uncertainty. Ergon and Energex supported the user-pays approach and committed to focusing on this matter during the next phase of engagement.

With regard to Statement 4, it was clarified that during the customer feedback period, at 1:1 meetings some large councils voiced their concerns with the proposal to fund the capital cost of the customer funded conversions of Rate 2 conventional assets to LED for the 2025-30 period. These customers suggested this approach would result in an overcharge on contributed Rate 2 LED assets. Subsequently, a revised approach was proposed to recover the capital and operating cost components for the Rate 2 conversions funded by Ergon and Energex via a new tariff Rate 2A. To reduce public lighting tariff complexity, it was proposed to retire tariff Rate 4 from 1 July 2025. The reasoning for this approach was:

- Rate 4 tariffs have had little uptake to date and customers are unlikely to have any appetite to self-fund LED conversions going forward in light of the adoption of the accelerated LED deployment option.
- It avoids adding any new public lighting tariffs.

<u>AER comments</u>

The AER noted the bespoke engagement on public lighting and that the proposals reflect what the networks heard from that engagement.

RRG comments

In our Engagement Report the RRG notes that Ergon and Energex were prepared to listen to customers' formal and informal feedback and reflect that feedback in the Regulatory Proposal. We highlighted this bespoke program as an exemplary example of effective customer engagement.