FINAL DECISION

Ergon Energy
Distribution Determination
2020–21 to 2024–25

Attachment 5
Capital expenditure

June 2020

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to Ergon Energy for the 2020–25 regulatory control period. It should be read with all other parts of the final decision, which includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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Attachment 10 – Service target performance incentive scheme

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5 Capital expenditure

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

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).[1]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[2] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the National Electricity Objective (NEO)).[3]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[4] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Appendix A outlines further detailed analysis of our final decision.

Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our ex-ante incentive-based regulatory framework and is often referred to as the 'capex bucket'.

Once the ex-ante capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. This incentive-based framework recognises that distributors should have the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

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1 NER, cl. 6.5.7(a).

2 NER, cl. 6.5.7(c).

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

4 AER, *Capex assessment outline for electricity distribution determinations,* February 2020.

Distributors may need to undertake programs or projects that they did not anticipate during the reset. Distributors also may not need to complete some of the programs or projects proposed if circumstances change. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly. Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs. As noted previously, distributors may spend more or less than our forecast in response to unanticipated changes.

5.1 Final decision

We do not accept Ergon Energy's revised capex forecast of $2804.3 million.[5] We are not satisfied that its revised total net capex forecast reasonably reflects the capex criteria. Our substitute estimate of $2276.2 million is 19 per cent below Ergon Energy's revised forecast. We are satisfied that our substitute estimate reasonably reflects the capex criteria. Our substitute estimate will allow Ergon Energy to maintain the safety, service quality and reliability of its network, consistent with its legislative obligations. Table 5.1 outlines our final decision.

Table 5.1 – Final decision on Ergon Energy's total net capex forecast ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy's revised proposal	551.6	568.8	580.7	549.5	553.7	2804.3
AER final decision	457.5	461.6	462.7	442.7	451.8	2276.2
Difference ($)	-94.1	-107.2	-118.0	-106.8	-101.9	-528.1
Percentage difference (%)	-17%	-19%	-20%	-19%	-18%	-19%

Source: Ergon Energy's updated revised PTRM and AER analysis.[6]
Note: Numbers may not sum due to rounding.

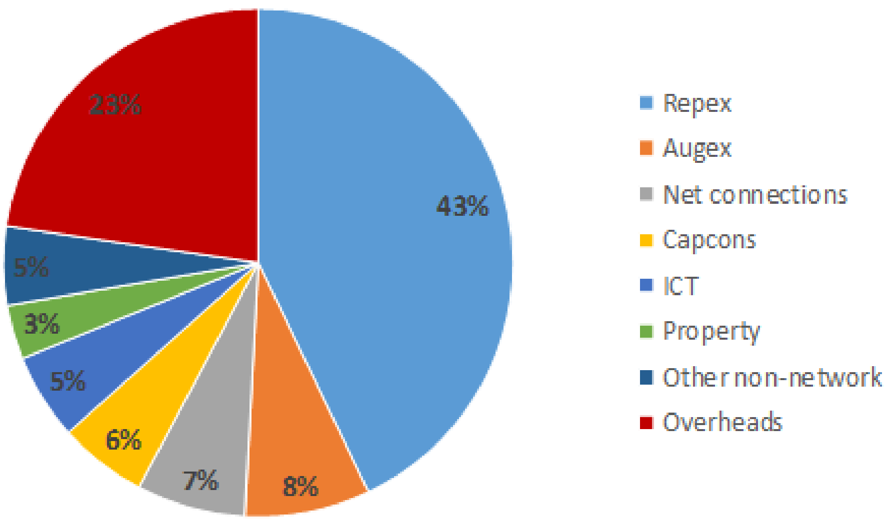
5.2 Ergon Energy's revised proposal

Ergon Energy's revised capex forecast for the 2020–25 regulatory control period is $2804.3 million. This is $522.4 million (23 per cent) higher than its actual and estimated capex over the current (2015–20) period and $80.1 million (3 per cent) higher than its initial capex forecast. Figure 5.1 outlines its revised capex forecast by capex driver. Figure 5.2 outlines Ergon Energy's historical capex performance against its forecast capex.

5 All dollar amounts are presented in real $2019–20 unless otherwise noted.

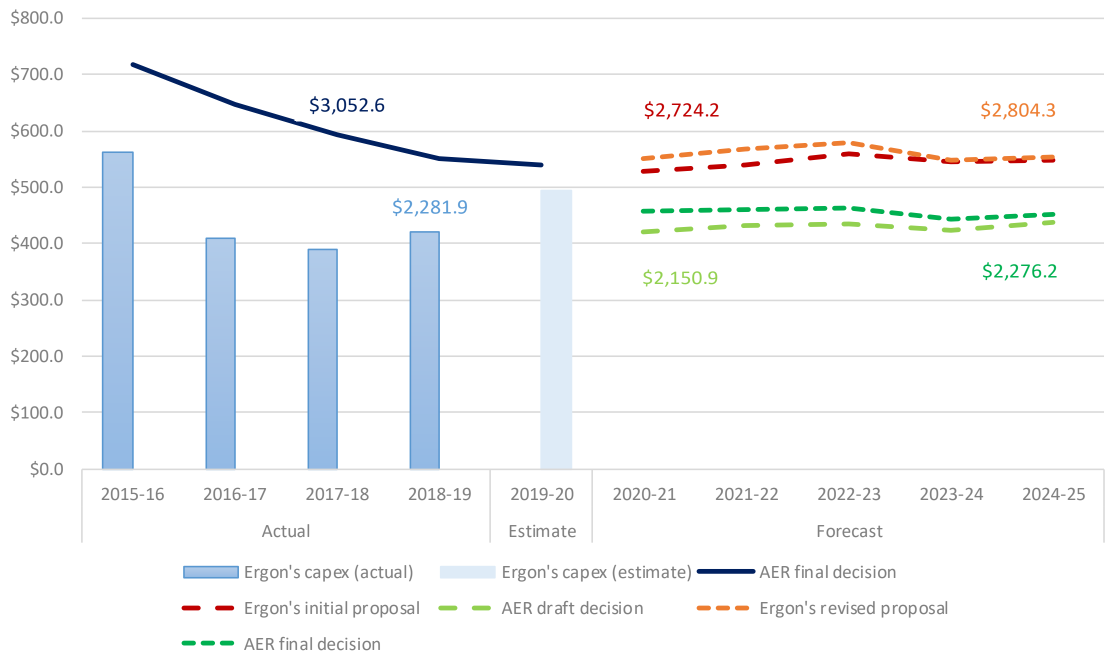
6 Ergon Energy updated its revised capex forecast due to a capex modelling error.

Figure 5.1 – Ergon Energy's total gross capex forecast ($2019–20)



Source: Ergon Energy's revised proposal and AER analysis.

Figure 5.2 – Ergon Energy's historical vs forecast capex snapshot ($ million, 2019–20)



Source: Ergon Energy's revised proposal and AER analysis.
Note: Ergon Energy's actual and estimated capex is based on its recast category analysis RIN data, which reflects Ergon Energy's new CAM that will apply for the 2020–25 regulatory control period. The 2015–20 AER final decision forecast therefore is not directly comparable with the historical and forecast capex amounts shown.

5.3 Reasons for final decision

We are not satisfied that Ergon Energy's total capex forecast reasonably reflects the capex criteria. Appendix A outlines how we have applied our assessment techniques and how we came to our position. 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.

We are therefore required to set out a substitute estimate.[7] We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and forms part of an overall distribution determination that is likely to contribute to the achievement of the NEO to the greatest degree.

Table 5.2 outlines the capex amounts by driver that we have included in our substitute estimate of $2276.2 million. Table 5.3 summarises the reasons for our substitute estimate by capex driver. This reflects the way we have assessed Ergon Energy's total capex forecast.

Our draft decision and ongoing engagement with Ergon Energy indicated that we typically expect distributors to support their proposals with quantified risk assessments where appropriate. Ergon Energy acknowledged this and its revised proposal included more quantitative support for its forecasts. However, we identified several critical modelling errors in this analysis, including inaccurate base case assessment and overstated risk calculations, most notably in its repex and property forecasts.

Several key stakeholders submitted that they did not support Ergon Energy's revised total net capex forecast. The Consumer Challenge Panel (CCP14) stated that consumers were uncomfortable with Ergon Energy reinstating almost all the proposed capital spending (other than ICT) from the initial proposal and did not seek to embrace opportunities for reductions in expenditure.[8] Energy Consumers Australia (ECA) also submitted that Ergon Energy's revised proposal is not capable of acceptance.[9]

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

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7 NER, cl. 6.12.1(3)(ii).

8 CCP14, *Submission on the draft decision and revised proposal – Ergon Energy, March 2020,* p. 17.

9 ECA, *Submission on Energy Queensland revised proposals,* January 2020, p. 1.

Table 5.2 – Capex driver assessment ($ million, 2019–20)

Driver	Ergon Energy's revised proposal	AER final decision	Difference ($)	Difference (%)
Augex	239.5	211.7	-27.8	-12%
Gross connections	376.7	376.7	0.0	-0%
Repex	1289.6	891.8	-397.8	-31%
ICT capex	164.4	164.4	0.0	-0%
Property capex	103.8	65.8	-38.0	-37%
Other non-network capex	150.5	150.5	0.0	-0%
Capitalised overheads	682.2	609.5	-72.6	-11%
Gross capex	**3006.6**	**2470.4**	**-536.2**	**-18%**
less capital contributions	169.0	169.0	0.0	-0%
less asset disposals	20.9	20.9	0.0	-0%
less Ergon Energy's modelling adjustments	12.5	12.5	0.0	-0%
less AER modelling adjustments	-	8.1	-	-
Net capex	**2804.3**	**2276.2**	**-528.1**	**-19%**

Source: Ergon Energy's updated revised PTRM and AER analysis.
Note: Numbers may not sum due to rounding. Modelling adjustments relate to Ergon Energy’s CPI and real price escalation assumptions. Gross capex is presented before any modelling adjustments are applied.

Table 5.3 – Summary of our findings and reasons

Issue	Findings and reasons
Total capex consideration	Ergon Energy has not supported or justified its significant increase in forecast capex. Its governance and management framework led to a significantly overstated total capex forecast. Ergon Energy has applied its forecasting methodology inconsistently and many programs and projects lack adequate risk-based cost-benefit analysis.
Augex	We have included Ergon Energy's proposed subtransmission growth and power quality augex in our substitute estimate. However, Ergon Energy has not fully supported its revised network communications augex.
Connections	We accept Ergon Energy's revised connections capex forecast. We accepted its initial connections forecast in our draft decision and Ergon Energy has updated its forecast with minor modelling adjustments.

Issue	Findings and reasons
Repex	Ergon Energy's revised repex forecast is significantly higher than its historical expenditure and higher than its initial proposal. Its revised repex forecast also significantly exceeds our revised repex model results. Our bottom-up assessment highlighted that Ergon Energy's underlying network risks are heavily overstated, leading to an overstated repex forecast required to address these risks.
ICT	We accept Ergon Energy’s revised ICT capex forecast. Ergon Energy accepted our draft decision on ICT capex subject to a minor modelling adjustment to recurrent ICT capex.
Property	Our draft decision highlighted issues with six property projects. Ergon Energy accepted our accepted our position for two of these projects and has reproposed the other four projects. It has demonstrated the prudency and efficiency of the Rockhampton data centre replacement, but not the Maryborough depot, Townsville training facility and property security projects.
Other non-network capex	We accept Ergon Energy’s revised other non-network capex forecast based on the additional information it has provided.
Capitalised overheads	We have adjusted Ergon Energy's base year and forecast output and price change calculations. We have also adjusted Ergon Energy's variable overheads based on our lower direct capex substitute estimate.
Ergon Energy's modelling adjustments	Ergon Energy's revised capex model did not allocate any forecast capex to contracted labour. We queried this allocation[10] and Ergon Energy advised that its revised capex model incorrectly allocated contracted labour to internal labour.[11] It subsequently provided an updated capex model and PTRM to correct for this error.[12] This resulted in a $12.5 million reduction to its total net capex forecast, as highlighted in Table 5.2.
AER modelling adjustments	Our modelling adjustments relate to Ergon Energy’s CPI and real price escalation assumptions. We have updated the year-on-year CPI and real labour price escalation assumptions in Ergon Energy's capex model. These inputs are now consistent with other aspects of our decision.

10 AER, *Information request 87,* January 2020.

11 Ergon Energy, *Response to information request 87,* February 2020.

12 Ergon Energy, *Follow-up response to information request 87,* February 2020.

A Capex driver assessment

This appendix outlines our detailed analysis of Ergon Energy's capex driver category forecasts for the 2020–25 regulatory control period. These categories are augmentation capex (augex), connections capex, replacement capex (repex), ICT capex, property capex, other non-network capex, and capitalised overheads. All dollar amounts are presented in real $2019–20 unless otherwise noted.

We used various qualitative and quantitative assessment techniques to assess the different elements of Ergon Energy's proposal to determine whether its proposal reasonably reflects the capex criteria. More broadly, we seek to promote the NEO and take into account the revenue and pricing principles set out in the NEL.[13] In particular, we take into account whether our overall capex forecast will provide Ergon Energy with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[14]

When assessing capex forecasts, we also consider:

- The prudency and efficiency criteria in the NER are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers to achieve the expenditure objectives.[15]
- Past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[16]
- The capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the service target performance incentive scheme (STPIS).[17]
- The annual benchmarking report, which includes total cost and overall capex efficiency measures, and considers a distributor's inputs, outputs and its operating environment.
- The interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[18]

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13 NEL, ss. 7, 7A and 16(1)-(2).

14 NEL, s. 7A.

15 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8–9.

16 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

17 The STPIS provides incentives for distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

18 NEL, s. 16(1)(c).

A.1 Augex

The need to build or upgrade the network to address changes in demand and network utilisation typically triggers augex. The need to upgrade the network to comply with quality, safety, reliability and security of supply requirements can also trigger augex.

A.1.1 Final decision

Ergon Energy has not demonstrated that its revised augex forecast of $239.5 million is prudent and efficient. We have included $211.7 million for augex in our substitute estimate of total capex, which is $27.8 million (12 per cent) lower than Ergon Energy's revised forecast. We consider this amount is prudent and efficient, and would form part of a total forecast capex forecast that reasonably reflects the capex criteria.

A.1.2 Ergon Energy's revised proposal

Ergon Energy has revised its augex forecast to $239.5 million for the 2020–25 regulatory control period. This represents a 4 per cent decrease relative to its $248.5 million original proposal. It has resubmitted all business cases with additional supporting information and has revised down the proposed expenditure for some network communications projects.

A.1.3 Reasons for final decision

We have included Ergon Energy's proposed subtransmission growth and power quality augex in our substitute estimate. However, its proposed network communications augex remains not fully justified. We discuss these programs and the other augmentation subcategories we have reviewed separately.

Networks communications augex

Evidence gaps remain in Ergon Energy's network communications augex program. Dynamic Analysis is generally supportive of Ergon Energy's networks communications programs, but shares our view that there are still residual evidence gaps that Ergon Energy may be able to close.[19] Our substitute estimate of $37.9 million includes a proportion of Ergon Energy's proposed augex for each of the following programs:

- **Intelligent grid enablement –** Ergon Energy addressed our key concerns[20] for two of the six projects that make up this program by showing that they are NPV positive. These projects relate to a low-voltage management system and to enable better analysis of data (‘real-time analytics’). Ergon Energy quantified the value of

[19] Dynamic Analysis, *Technical report on Ergon revised proposal*, January 2020, p. 10.

[20] AER, *Attachment 5: Capital expenditure – Draft decision – Ergon Energy 2020–25*, October 2019, pp. 5, 24–25.

the exports that static limits would otherwise constrain without these projects.[21] We encourage Ergon Energy to share learnings from implementing these projects and to work with other distributors and AEMO to adopt best practice technical approaches.

However, Ergon Energy has not sufficiently addressed our concerns for the remaining four projects, which we have not included in our substitute estimate. Its proposed distributed energy resources (DER) management system would allow large business customers to increase electricity exports, but did it not quantify these benefits. It also did not quantify the benefits from improving its demand management systems. For the Digital Control Room Visualisation and Digital Power Worker Network Awareness projects, Ergon Energy did not quantify any efficiency benefits or otherwise demonstrate the need for these projects under the NER.[22]

- **Back-up protection** – Ergon Energy has demonstrated some need for backup protection augmentation, but has not fully addressed concerns we raised in our draft decision.[23] We have included half of Ergon Energy's proposed augex in our substitute estimate.

  Ergon Energy has reiterated a need under NER clause S5.1.9 to ensure backup systems are in place to detect and automatically clear any given fault.[24] We also received a submission from the Queensland Electrical Safety Office supporting the proposed program, referencing NER clause S5.1.9 and the need to ensure primary and backup protection systems are in place.[25]

  We recognise that Ergon Energy needs to address protection schemes where it does not provide adequate safety and asset protection outcomes. We have included half the proposed expenditure in our substitute estimate based on Ergon Energy's revealed practices,[26] which will allow it to address protection shortfalls that it identifies and validates. Ergon Energy's revealed practices serve as an appropriate basis for our substitute estimate, recognising that its regulatory obligation is unchanged.

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21 In its response to information request 74, Ergon Energy stated that these two projects would be sufficient to realise the quantified benefits (Q10 p. 18). In its response to information request 88, Ergon Energy also provided the NPV of these projects alone, showing that this is the highest NPV option (Q2 p.1).

22 Ergon Energy, *Business Case – Intelligent Grid Enablement*, December 2019, pp. 17–19.

23 AER, *Attachment 5: Capital expenditure – Draft decision – Ergon Energy 2020–25,* October 2019, pp. 5–25.

24 Ergon Energy, *Revised proposal business case - backup reach program,* December 2019, p. 4.

25 Queensland Electrical Safety Office, *Submission on EQL draft determination,* January 2020, p. 2.

26 Ergon Energy explained that it has not augmented its backup protection systems in 2015-20 regulatory control period, but has initiated works to remediate primary protection concerns. Our forecast estimate is based on its estimated underspend on protection augex for the 2015–20 regulatory control period. It expects to incur $8.6 million for all network-initiated protection augmentation works in the current period (2015–20), approximately half the $17.0 million ($2014–15) it proposed. Ergon Energy, Response to information request 079, January 2020, pp. 1, 3; Ergon Energy, Revised Regulatory proposal: July 2015 to June 2020 Attachment 07.00.04, July 2015, p. 28.

However, Ergon Energy's business case is based on a desktop analysis to identify protection shortfalls based on its internal technical standards.[27] Ergon Energy's internal technical standards cannot be treated as compliance requirement. To justify this program, Ergon Energy needs to demonstrate that its current protection schemes do not effectively protect network assets or do not ensure public safety. Further, in the absence of field testing that supports the desktop analysis, we do not have confidence that the desktop analysis represents an accurate calculation of backup protection shortfalls. It has previously stated that field testing reduced the scope and associated capex for some protection projects.[28]

- **Telecommunications network capacity and coverage –** We have included two of the three subcomponents of the proposed telecommunications program in our substitute estimate. This results in a higher substitute estimate relative to our draft decision. However, Ergon Energy has not fully addressed our concerns on the need for the telecommunications transmission augmentation subcomponent.[29] For this subcomponent, Ergon Energy did not provide a quantitative risk assessment to demonstrate the impacts of shortfalls in communications capacity. It also did not provide supporting evidence that protection failures may occur as a result of communications failure.
- **Protection upgrades supporting DER** – We consider it would be prudent for Ergon Energy to undertake pilot programs to understand the effectiveness of its proposed solutions. Our substitute estimate is commensurate with this objective, allowing Ergon Energy to trial the proposed protection systems at four subtransmission sites and to undertake the proposed distribution network pilot project.[30]

  Ergon Energy provided an example of one event where a fault on the 66kV network was back-energised,[31] but it did not provide information to demonstrate the likelihood of such events occurring. It would not be prudent to roll out protection schemes at the scale proposed when the level of risk is unclear. Islanding in the subtransmission system is less likely than in distribution system, because the DER capacity is less likely to exceed total load in the subtransmission system than in local distribution areas.

Other augmentation subcategories

We have included Ergon Energy's proposed subtransmission augmentation and power quality augex in our substitute estimate:

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27 Ergon Energy, *Revised proposal business case - backup reach program, December 2019,* p. 8.

28 Ergon, *2015–20 revised regulatory proposal – Attachment 07.00.04,* July 2015, p. 12.

29 AER, *Attachment 5: Capital expenditure – Draft decision – Ergon Energy 2020–25, October 2019,* pp. 5–28.

30 Ergon Energy, *Revised proposal business case - protection upgrades to support increasing distributed energy resources,* December 2019, pp. 10–11.

31 Ergon Energy, *Revised proposal business case - protection upgrades to support increasing distributed energy resources,* December 2019, p. 2.

- **Subtransmission augmentation** – Ergon Energy has addressed our concerns for the four following subtransmission augmentation projects:[32]
    - Cloncurry supply reinforcement – Ergon Energy addressed our concerns regarding dispatch timeframes and follow-up questions on operation of the DR-CC-1 line.[33]
    - Blackwater replacement and reinforcement – Ergon Energy has revised the scope and timing of the project,[34] which has resulted in a more efficient outcome.
    - Broxburn, Yarranlea replacement and reinforcement – We consider that the proposed works at Yarranlea South zone substation are justifiable due the current inability to share load between transformers.[35]
    - East Bundaberg to Burnett Heads 66kV line build – Ergon Energy explained the technical limitations of adopting interim solutions that may have allowed construction of the proposed feeder to be postponed.[36]
- **Power quality** – Ergon Energy's revised model for its power quality monitoring program includes savings associated with avoiding the installation of new voltage regulators.[37] Ergon Energy should not have included this benefit, but instead should have only included the avoided cost for manually collecting voltage performance data. If Ergon Energy has been installing voltage regulators unnecessarily without manual collection of voltage performance data, then those investments were not prudent. We removed this benefit from Ergon Energy's modelling, but the overall proposal remained NPV positive. We have therefore included the power quality program in our substitute estimate.

A.2 Connections capex

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet new customer demand.

A.2.1 Final decision

We are satisfied that Ergon Energy's net connections capex forecast of $207.8 million and contributions forecast of $169.0 million would form part of a total capex forecast

32 AER, *Attachment 5: Capital expenditure – Draft decision – Ergon Energy 2020–25,* October 2019, pp. 5, 17–21.

33 Ergon Energy, *Revised proposal business case - Cloncurry supply reinforcement,* December 2019, p. 23; Ergon Energy, *Response to information request 90,* February 2020, pp. 1–2.

34 Ergon Energy, *Revised proposal business case - Blackwater substation reinforcement,* December 2019, pp. 9–11.

35 Ergon Energy, *Revised proposal business case - Pittsworth, Broxburn & Yarranlea South refurbishment and reinforcement,* December 2019, pp. 31–33.

36 Ergon Energy, *Revised proposal business case - Burnett Heads 66kV line augmentation,* December 2019, pp. 3–6.

37 Ergon Energy, *Revised proposal business case - power quality,* December 2019, p. 24.

that reasonably reflects the capex criteria. We have therefore included these amounts in our substitute estimate of total capex.

A.2.2 Ergon Energy's revised proposal

We accepted Ergon Energy's original connections proposal in our draft decision. Ergon Energy has updated its forecast with minor modelling adjustments.[38]

A.2.3 Reasons for final decision

Stakeholders identified that Ergon Energy had appeared to update its forecast of net new customers, raising concerns with this forecast[39] and noting that the associated connections capex forecast had not been revised.[40] Ergon Energy explained that it used a different definition of customer numbers[41] and that it was continuing to forecast increased connections at lower overall cost, relative to historical levels.[42] We are satisfied with Ergon Energy's explanation and have included its revised connections capex estimate in our substitute estimate.

A.3 Repex

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment determines that it is likely to fail soon or degrade in performance, such that it does not meet its service requirement and replacement is the most economic option[43]
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

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38 Ergon Energy, *Revised regulatory proposal 2020–25, December 2019,* pp. 29–30.

39 Queensland Electricity Users Network, *Submission - Ergon Network 2020–25 determination,* January 2020, pp. 6–8.

40 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 revised regulatory proposals,* March 2020, pp. 28–29.

41 Ergon Energy originally used the economic benchmarking regulatory information notice definition of customers which counts both energised and de-energised national metering identifiers (NMIs). It the revised proposal it excluded de-energised NMIs, aligning the definition of customers with network pricing. Ergon Energy, *Information request 82 follow up,* February 2020, pp. 3–4.

42 Ergon Energy, *Information request 82 follow up,* February 2020, p. 3.

43 A condition assessment may relate to assessment of a single asset or a population of similar assets. High-value/low-volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

The majority of network assets will remain in efficient use for far longer than a single five-year regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period.

A.3.1 Final decision

We do not accept that Ergon Energy's proposed repex of $1289.6 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included a repex forecast of $891.8 million in our substitute estimate of total capex. We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria. Table A.1 summarises Ergon Energy's revised repex forecast and our final decision.

Table A.1 – Final decision on Ergon Energy's repex forecast ($ million, 2019–20)

	Ergon Energy's proposal	AER final decision	Difference ($)	Difference (%)
Total repex	1289.6	891.8	-397.8	-31%

Source: Ergon Energy's reset RIN and AER analysis.
Note: Numbers may not sum due to rounding.

A.3.2 Ergon Energy's revised proposal

Ergon Energy proposed a revised repex forecast of $1289.6 million for the 2020–25 regulatory control period. It stated its repex forecast is predominantly targeted at managing its network to deliver on safety commitments to communities, customers and employees.[44] Ergon Energy's revised forecast is:

- $195.2 million (18 per cent) higher than its initial proposal
- $447.6 million (53 per cent) higher than our draft decision
- $390.5 million (43 per cent) higher than its actual and estimated capex over the current period (2015–20).

A.3.3 Reasons for final decision

We have applied several techniques to assess Ergon Energy's revised repex forecast against the capex criteria, as well as considering stakeholder submissions. These techniques include:

- trend analysis

[44] Ergon Energy, *Revised regulatory proposal,* December 2019, p. 28.

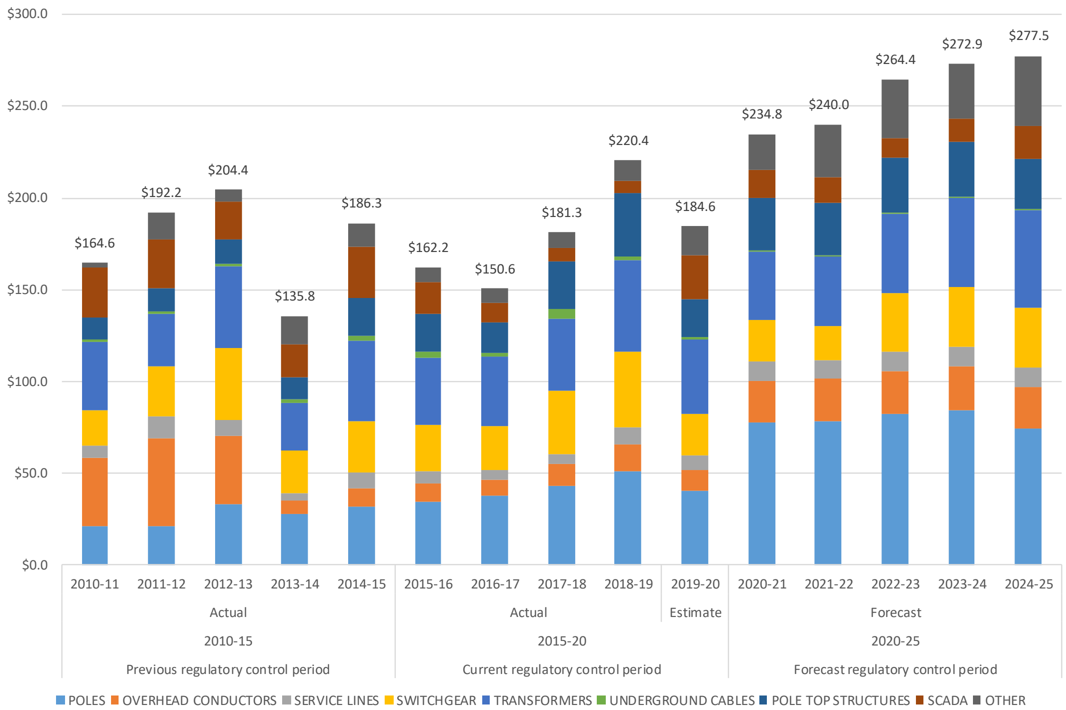
- repex modelling
- bottom-up program and project-level economic and engineering review.

Trend analysis

Figure A.1 highlights that Ergon Energy is forecasting a significant increase in repex for most asset groups over the forecast period. It is also forecasting a significant increase in replacement volumes for several key asset groups. Major increases include:

- Poles – repex (92 per cent) and replacement volumes (125 per cent)
- Overhead conductors – repex (103 per cent) and replacement volumes (312 per cent)
- Service lines – repex (53 per cent) and replacement volumes (66 per cent)
- Transformers – repex (7 per cent) and replacement volumes (38 per cent)
- Pole top structures – repex (21 per cent) and replacement volumes (12 per cent)
- Other – repex (188 per cent).

Figure A.1 – Ergon Energy's repex trend by asset group ($ million, 2019–20)



Source: Ergon Energy's revised proposal and AER analysis.
Note: Ergon Energy's clearance to ground and structure program has been apportioned to the asset groups above based on its initial proposal allocation, consistent with its historical expenditure.

Ergon Energy's revised poles forecast is $396.9 million, compared with its initial forecast of $279.9 million. In our draft decision, we highlighted concerns that its initial poles forecast represented an increase compared with the current period (actual and estimated repex of $206.8 million) and was not supported with risk-based cost-benefit analysis. However, our substitute estimate ($284.9 million), which was derived using the repex model, was broadly in line with Ergon Energy's initial forecast.

Ergon Energy subsequently increased its poles forecast by $117.0 million (42 per cent) in its revised proposal. It did not explain why its poles forecast changed so significantly from its initial proposal. Several stakeholder submissions including CCP14 and ECA raised concerns with Ergon Energy increasing its forecasts without explanation. CCP14 noted that the proposed repex increase "presents a real dent in Energy Queensland's credibility that it has its long-term asset management under control".[45]

Repex modelling

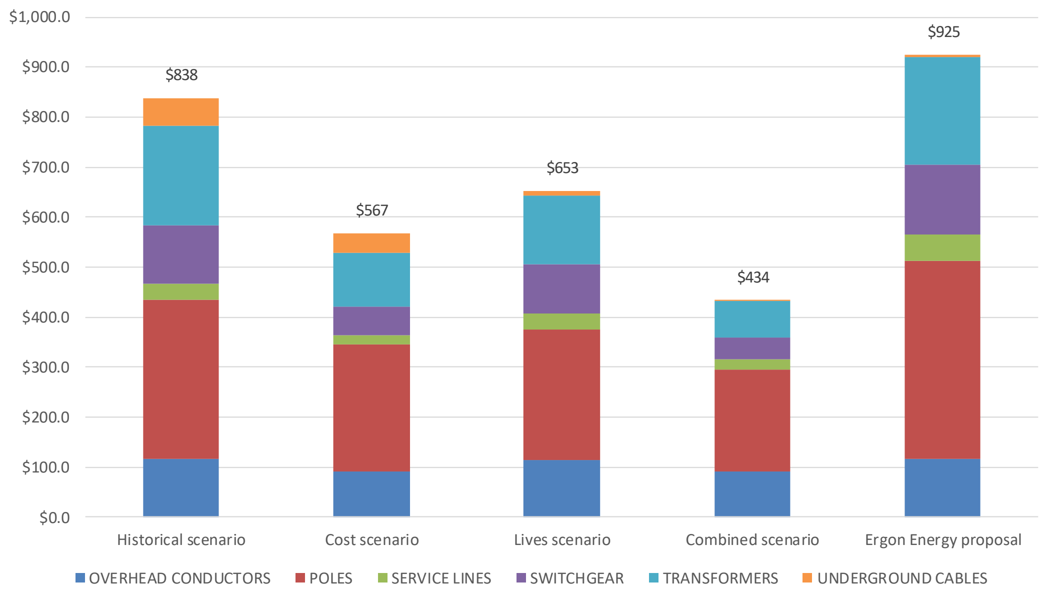
We use the repex model to forecast replacement volumes and expenditure for the poles, overhead conductors, service lines, switchgear, transformers and underground cables asset groups. Our capex assessment outline provides more detail on our repex modelling approach.[46] Figure A.2 outlines our revised repex model results. Ergon Energy's revised modelled repex forecast ($924.6 million) is substantially higher than its initial modelled repex forecast ($765.0 million). This is primarily due to Ergon Energy increasing its:

- revised poles repex and replacement volumes forecasts
- clearance to ground and structure breach remediation program (discussed in more detail below).

45 CCP14, *Submission on the draft decision and revised proposal – Ergon Energy,* March 2020, p. 17.

46 AER, *Capital expenditure assessment outline,* October 2019, p.14.

Figure A.2 – Revised repex model results ($ million, 2019–20)



Source: Ergon Energy's revised proposal and AER analysis.
Note: Ergon Energy's clearance to ground and structure program has been apportioned to the modelled asset groups above based on its initial proposal allocation, consistent with its historical expenditure.

Figure A.2 highlights that Ergon Energy's revised modelled repex forecast is 44 per cent higher than our repex model threshold (lives scenario). It indicates that Ergon Energy's modelled asset categories are likely to have, on average, higher unit costs and shorter expected replacement lives than its own historical replacement practices (historical scenario) and compared with the historical replacement practices of the other 13 distributors in the National Electricity Market (cost and lives scenarios). The asset groups where Ergon Energy's revised forecasts substantially exceed our revised repex model results are ranked below:

- Poles – $137.0 million (53 per cent) difference
- Transformers – $77.4 million (56 per cent) difference
- Switchgear – $41.4 million (42 per cent) difference
- Service lines – $19.7 million (61 per cent) difference

The repex model results for overhead conductors are broadly in line with Ergon Energy’s revised forecast. Its revised service lines forecast is discussed in more detail below in conjunction with the low-voltage safety program. Lastly, we have not focused our analysis on the underground cable asset group as this was not a focus area in the draft decision and Ergon Energy's revised forecast remains immaterial. Our bottom-up analysis therefore primarily focused on Ergon Energy's poles, transformers and switchgear forecasts, as well as its unmodelled repex forecast.

Bottom-up assessment

Systemic issues

In response to feedback in our draft decision, Ergon Energy provided risk-based cost-benefit analysis models in its revised proposal to support its revised repex forecast. We acknowledge that Ergon Energy engaged with us on this aspect of its proposal and attempted to quantify the costs and benefits of a range of repex programs and projects.

However, we have identified several critical issues in this modelling. Below we outline these issues, our expectations, the subsequent results and relevant examples within Ergon Energy's revised proposal. ECA and its consultant, Dynamic Analysis, raised similar concerns in its submissions, particularly with Ergon Energy's poles, service lines and pole top structures business cases.[47]

Options analysis

Several of Ergon Energy's cost-benefit analysis lack sufficient options analysis. For example, Ergon Energy’s pole model lacks sufficient options analysis, as the preferred option is only compared with one other option. In both cases, the replacement volumes selected appear arbitrary.

In addition, several transformer models lack sufficient options analysis, as in most cases only the preferred option (replacement) is considered. Other options including deferral, refurbishment or non-network solutions have not been considered. We generally expect several reasonable options to be considered in rigorous cost-benefit analysis, to ensure the optimal option is chosen on consumers’ behalf.

Disproportionality factors

The Work Health and Safety Act (2011), which mirrors the Electrical Safety Act (QLD) 2002, outlines that distributors have a legislative requirement to:

- eliminate risks to health and safety, so far as is reasonably practicable
- if it is not reasonably practicable to eliminate risks to health and safety, to minimise those risks so far as is reasonably practicable.[48]

The model work health and safety framework requires prudent avoidance of safety risks and states that actions should be taken to avoid, reduce or mitigate safety risks so far as is reasonably practicable.[49] The UK Health and Safety Executive provides

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47 Energy Consumers Australia, *Dynamic Analysis submission on Ergon’s revised proposal,* January 2020.

48 Australian Government, *Work Health and Safety Act 2011,* July 2018, p. 25.

49 The UK Health and Safety Executive provides more information on the 'so far as is reasonably practicable' principle.

more information on the 'so far as is reasonably practicable' principle.[50] Disproportionality factors are used within this framework to account for the inherent variance that occurs when calculating uncertain variables.

Ergon Energy's cost-benefit analysis models include disproportionality factors of up to 10 for its safety-related consequences. This overstates Ergon Energy's safety risk calculations between two and three times. This subsequently overstates the amount of forecast repex (costs) that can reasonably be spent to reduce safety risks (benefits). Ergon Energy has overstated risk, and therefore the repex forecast, in several of its cost-benefit analysis models including poles, clearance to ground and structure, LV safety, transformers, switchgear and pole top structures. It provided a sample of its cost-benefit analysis models to us before it submitted its revised proposal. We met with Ergon Energy and provided a range of feedback, including that we considered it had relied on overstated disproportionality factors in its analysis. However, this was not addressed in its revised proposal.

We typically accept disproportionality factors between three and six. The effect of these values is that a distributor's expected safety consequence costs are multiplied by values between 3 and 6. Larger expected costs could therefore be spent to avoid, reduce or mitigate safety risks (benefits). This is consistent with the AER’s industry practice application note on asset replacement planning[51] and recent determinations including Transgrid’s 2018–23 draft decision and SA Power Networks’ 2020–25 final decision.

As outlined in SA Power Networks' 2020–25 final decision, disproportionality factors of up to 10 are often used in the nuclear industry. However, a distributor is unlikely to face a situation where an asset failure could result in large numbers of people being exposed to fatal conditions for long time periods, as is the case in the nuclear industry.

Asset failure and consequence event parameters

In several of Ergon Energy's models, its forecast asset failures and expected consequence events do not align with its historical network performance. We generally expect these forecast metrics to align with a network’s historical performance or comparable industry benchmarks.

For example, Ergon Energy’s forecast pole failures and expected consequence events do not align with its historical network performance. Its model indicates that its network experienced an average of 82 pole failures per year between 2016–17 and 2018–19. However, the model assumes 198 poles are expected to fail by 2020–21. This step change increase has not been supported. As a result, the risk calculations are

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50 UK Health and Safety Executive, *Risk management – ALARP at a glance,* available at https://www.hse.gov.uk/risk/theory/alarpglance.htm.

51 AER, *Industry practice application note – Asset replacement planning,* January 2019, p. 80.

significantly overstated and the amount of repex (costs) that can be spent to reduce safety risks (benefits) is subsequently overstated.

In addition, Ergon Energy's probability of consequence parameter assumptions for its low-voltage safety program are overstated. It has not based the assumptions for this parameter on historical experience. For example, Ergon Energy assumes that a low-voltage service line failure will result in a fatality to a member of the public once every six years. Ergon Energy's actual network performance data highlights that there has only been one fatality in over 20 years.

We agree that reducing safety risks is important and have included safety-related capex in previous decisions. In many decisions, we have acknowledged that where capex is proposed to meet health and safety risks, it is reasonable for forecast costs to be higher than the benefits of mitigating those risks. However, we do not accept costs that are grossly disproportionately higher than the benefits of mitigating health and safety risks.

Counterfactual

Some of Ergon Energy's models are based on an inaccurate business-as-usual counterfactual position, while others are a 'do-nothing' counterfactual. For example, the counterfactual option in its poles model is based on replacement volumes that do not align with its actual reported historical replacement volumes. We asked Ergon Energy about this misalignment[52] but it did not provide an explanation for the discrepancy.[53]

In other cases, Ergon Energy did not apply a 'do-nothing' counterfactual in its analysis. For its communications site infrastructure program, Ergon Energy stated a counterfactual 'do nothing' option was considered but rejected, as failure to replace buildings and structures would result in deterioration of the infrastructure's condition resulting in unacceptable risk to the communication network and increase the risk to staff, contractors and the community.[54] However, Ergon Energy did not quantify these risks, despite the feedback we provided in our draft decision and throughout our ongoing engagement. Ergon Energy's analysis highlights this program is NPV negative, and due to the lack of benefit quantification, it selected the least negative of the three options considered.[55]

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52 AER, *Information request 83,* January 2020.

53 Ergon Energy, *Response to information request 83,* January 2020, p. 4.

54 Ergon, *Business case – Communication site infrastructure,* December 2019, p. i.

55 Ergon, *Business case – Communication site infrastructure,* December 2019, p. i.

Program and project-level analysis

Clearance to ground and structure breach remediation program

Background

Ergon Energy's revised proposal includes $133.1 million to rectify overhead conductor clearance to ground and structure compliance breaches. Its forecast allocates all of this expenditure to the 'other' repex asset group. However, Ergon Energy provided information that shows that historically this expenditure has primarily been reported against modelled asset groups such as poles, transformers, overhead conductors, switchgear and service lines.

Therefore, we have correctly allocated the majority of this program (84 per cent) across the six modelled repex asset groups outlined in Figure A.1. The remaining 16 per cent is split across the pole top structures and other asset groups. These allocations are based on information Ergon Energy provided in response to an information request and is consistent with the way it has reported expenditure on these remediation works historically.[56]

Ergon Energy submitted that under the Queensland Electrical Safety Act (2002) and associated regulations, it has an obligation to ensure that its network is electrically safe and its overhead conductors must be mandated distances away from the ground and nearby structures.[57] Ergon Energy's initial proposal only included $14.0 million for this program. It also used the same approach during its 2015–20 determination. Its 2015–20 revised proposal included $39.2 million for a conductor clearance to ground backlog remediation program, after its initial proposal did not include this program.

Business case and cost-benefit analysis

Ergon Energy is forecasting that it will need $133.1 million to remediate 22,486 clearance breaches in the forecast period. This is made up of 7,846 current defects and 15,000 expected defects based on an extrapolation of worst-case scenarios. However, over the last three years, it spent $69.2 million to remediate 21,601 defects.[58] Ergon Energy is therefore proposing to spend nearly twice as much repex to rectify a similar number of clearance breaches.

Its forecast unit cost to rectify these breaches is $5,919, an increase of 85 per cent compared with its historical unit cost of $3,201. In addition, its revised forecast unit cost ($5,919) is 12 per cent higher than its initial forecast unit cost ($5,274). Its revised proposal did not include any information that explained this change or why its forecast unit cost is nearly twice as high as its historical revealed costs. Its information request

56 Ergon Energy, *Response to information request 017 – Distribution reset RIN apportionment,* May 2019.

57 Ergon Energy, *Overhead conductor clearance business case,* December 2019, p. 2.

58 Ergon Energy, *Response to information request 83,* January 2020, pp. 9–10.

response also did not adequately explain the difference and stated the “unit rate is higher than first quoted”.[59]

Information requests and stakeholder submissions

We sent numerous information requests to Ergon Energy asking for additional information to support this program, including its significantly higher forecast unit costs. Ergon Energy did not provide evidence that adequately supported its business case. In some instances, the responses were inconsistent with the business case and other information in the same response.

The Queensland Electrical Safety Office (ESO) submitted that it supports the safety improvement initiatives proposed in this revised business case. However, this submission did not provide any explanation or commentary on the significant increase in forecast unit costs for this program, and why Ergon Energy would need nearly twice as much repex to rectify broadly the same number of breaches that it has remediated in the current period (2015–20).

Several stakeholders raised concerns with customers paying for significant increases in repex, including this program, particularly given Ergon Energy’s significant underspend in the current period. CCP14 stated that there is a disconnect between the emotive public safety argument that was presented to consumers and the compliance argument that was presented in Ergon Energy’s business case and options analysis.[60] Overall, Ergon Energy has not provided sufficient information to support shifting from its business-as-usual replacement practices to a significantly larger program in dollar terms, and to incur nearly twice as much expenditure to remediate broadly the same number of clearance breaches. Below we outline the repex forecast we have included in our substitute estimate of total capex.

Low-voltage safety

Background

Ergon Energy’s proposal includes $44.0 million for a low-voltage (LV) safety program to install network monitoring devices (NMDs). Ergon Energy states that this program will allow it to monitor and respond to service line neutral faults and failures in real time.[61] It describes the investment need as a means to optimise economic and community safety outcomes.

The LV safety program is linked with Ergon Energy’s service line replacement program. Its revised proposal includes $17.9 million (53 per cent) for service line replacements above its current levels. Our draft decision included no repex for LV

59 Ergon Energy, *Response to information request 83,* January 2020, p. 9.

60 CCP14, *Submission on the draft decision and revised proposal – Ergon Energy,* March 2020, p. 30.

61 Ergon states that it will examine purchasing smart meter data in lieu of installing an NMD for some customers.

safety and $28.6 million for service line replacements, compared with Ergon Energy's initial forecast of $53.6 million. In our draft decision, we stated that Ergon Energy:

- did not justify the LV safety program on economic or legislative grounds
- was already managing its risks in a manner consistent with good industry practice.[62]

Business case and cost-benefit analysis

In its revised proposal, Ergon Energy revised its business case and quantitative cost-benefit analysis to support this program. The analysis claims that the proposed program is required to comply with relevant safety legislation. Ergon Energy's analysis also claims that the costs of the LV safety program are not grossly disproportionate to the benefits (safety risk reductions) and are therefore reasonably practicable.[63]

However, as highlighted above, we disagree with the assumptions used to quantify risks, particularly the safety risks, in Ergon Energy's analysis. Importantly, it has not based its assumptions for the probability and consequence of risks on historical experience. In addition, it uses disproportionality factors of up to 10 its analysis, which as noted above, overstates the safety risk calculations between two and three times. When these parameters are corrected, Ergon Energy's model shows its preferred option is NPV negative. Therefore, this program is not prudent and efficient. Based on the information we have received, the costs of Ergon Energy's low-voltage safety program appear grossly disproportionate to the risk reduction benefits.

Information requests and stakeholder submissions

We sent several information requests to and had numerous meetings with Ergon Energy. Following its revised proposal, we sent an information request asking for additional information to support the LV safety program.[64] Its response provided no evidence that materially supported its business case.

The Queensland ESO submitted that it supports the safety improvement initiatives proposed in the revised business case for LV network safety.[65] It also stated that in accordance with the Queensland Electrical Safety Act, Ergon Energy has a duty of care to eliminate or minimise risks associated with the operation of its network so far as is reasonably practicable.[66] We agree, but as highlighted in our draft decision, the costs of this risk mitigation should be considered, including whether the cost is grossly disproportionate to the risk.[67] As highlighted above, our analysis shows the costs of this program appear grossly disproportionate to the risk reduction benefits.

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62 AER, *Draft decision – Ergon Energy 2020–25 distribution determination,* October 2019, p. 11.

63 Ergon Energy, *Business case – LV network safety,* December 2019, p. 1.

64 AER, *Information request 85,* January 2020.

65 ESO, *Submission on EQL draft determination,* January 2020, p. 1.

66 ESO, *Submission on EQL draft determination,* January 2020, p. 2.

67 Australian Government, *Work Health and Safety Act 2011,* September 2018, s18.

We do not downplay the dangers of neutral failures. However, the evidence we have received shows that there has only been one recorded neutral failure incident leading to a fatality and no injuries or fires resulting from neutral failures. This evidence does not reconcile with Ergon Energy's risk-based modelling. Overall, Ergon Energy has not adequately supported that its LV safety program is required to maintain its service level outcomes. Below we outline the repex forecast we have included in our substitute estimate of total capex.

Repex forecast included in substitute estimate

We must not accept a distributor's forecast if we are not satisfied that it reasonably reflects the capex criteria, taking into account the capex factors.[68] Based on the repex assessment outlined above, Ergon Energy has not adequately demonstrated that its revised repex forecast would form part of a total capex forecast that reasonably reflects the capex criteria.

Therefore, we must set out a substitute estimate for total capex that we are satisfied reasonably reflects the capex criteria, taking into account the capex factors.[69] Table A.2 outlines Ergon Energy's revised repex forecasts and our final decision forecasts by asset group. It also outlines the assessment approach we used to determine our forecasts.

Table A.2 – Final decision repex forecast ($ million, 2019–20)

Asset group	Ergon Energy's revised proposal	AER final decision	Difference	Approach used
Poles	$396.6	$260.0	-$136.9 (-34%)	Repex model
Overhead conductors	$116.0	$115.2	-$0.7 (-1%)	Repex model
Service lines	$52.0	$52.0	$0.0 (0%)	
Switchgear	$139.2	$97.8	-$41.4 (-30%)	Repex model
Transformers	$219.4	$138.8	-$80.6 (-37%)	Repex model
Underground cables	$4.2	$9.0	$4.8 (116%)	Repex model
Pole top structures	$144.0	$122.6	-$21.5 (-15%)	Current period trend
SCADA	$69.8	$52.6	-$17.2 (-25%)	Current period trend
Other	$148.1	$43.8	-$104.2 (-70%)	Current period trend
Total	**$1289.6**	**$891.8**	**-$397.8 (-31%)**	

Source: Ergon Energy's revised proposal and AER analysis.
Note: Numbers may not sum due to rounding. Current period trend is based on four years of actual expenditure from the current period (2015–20), prorated to a five-year period.

68 NER, cl. 6.5.7(d).

69 NER, cl. 6.12.1(3)(ii).

Clearance to ground and structure breach remediation program

As highlighted above, Ergon Energy's forecast for this program has been allocated to the 'other' repex asset group, whereas it has historically reported this expenditure primarily against modelled asset groups. This historical repex is captured in both trend analysis (Figure A.1) and our repex model results (Figure A.2).

Therefore, our substitute estimate outlined in table 3, which is derived using the repex model and trend analysis, includes the historical repex of $69.2 million that Ergon Energy has spent remediating clearance breaches during the current period (2015–20).[70] As noted above, this amount was spent to rectify 21601 defects during this period.

Therefore, we consider $69.2 million, which is included in our substitute estimate, would provide a prudent and efficient operator with sufficient resources to respond to the clearance to ground and structure breaches Ergon Energy has identified. Based on the information we have received, it would be able to respond to broadly the same number of clearance breaches as it remediated in the current period.

Low-voltage safety and service lines programs

We tested Ergon Energy’s modelling for the LV safety program, including correcting modelling errors and adjusting its overstated assumptions. Our analysis indicates that Ergon Energy’s counterfactual position to not install any NMDs and to continue historical service line replacement volumes was the highest NPV option of the options analysed. We also tested an additional option, which is to not install any NMDs and to replace the increased number of service lines that Ergon Energy forecast in its revised proposal.

Based on the information we have received, this additional option has the highest net benefit of all the options considered. Therefore, despite the trend analysis and repex modelling concerns highlighted above for service lines, our final decision repex forecast includes Ergon Energy's revised service lines forecast of $52.0 million. However, it does not include Ergon Energy's low-voltage safety program. As highlighted above, the costs of this program appear grossly disproportionate to the risk reduction benefits, and an increased service lines forecast to address the root cause of the risk is the highest NPV option.

Total repex

Our substitute estimate ($891.8 million) is broadly in line with Ergon Energy’s actual and estimated repex over the current period (2015–20) ($899.1 million). We agree with ECA's consultant Dynamic Analysis, who submitted that Ergon Energy’s business cases revealed evidence gaps and that there was insufficient evidence to support the

[70] Ergon Energy, *Response to information request 17 – Distribution reset RIN apportionment,* May 2019.

step change compared with current levels.[71] We typically place a substantial amount of weight on a distributor's revealed costs, as repex is generally recurrent in nature and given the incentive-based regulatory framework.

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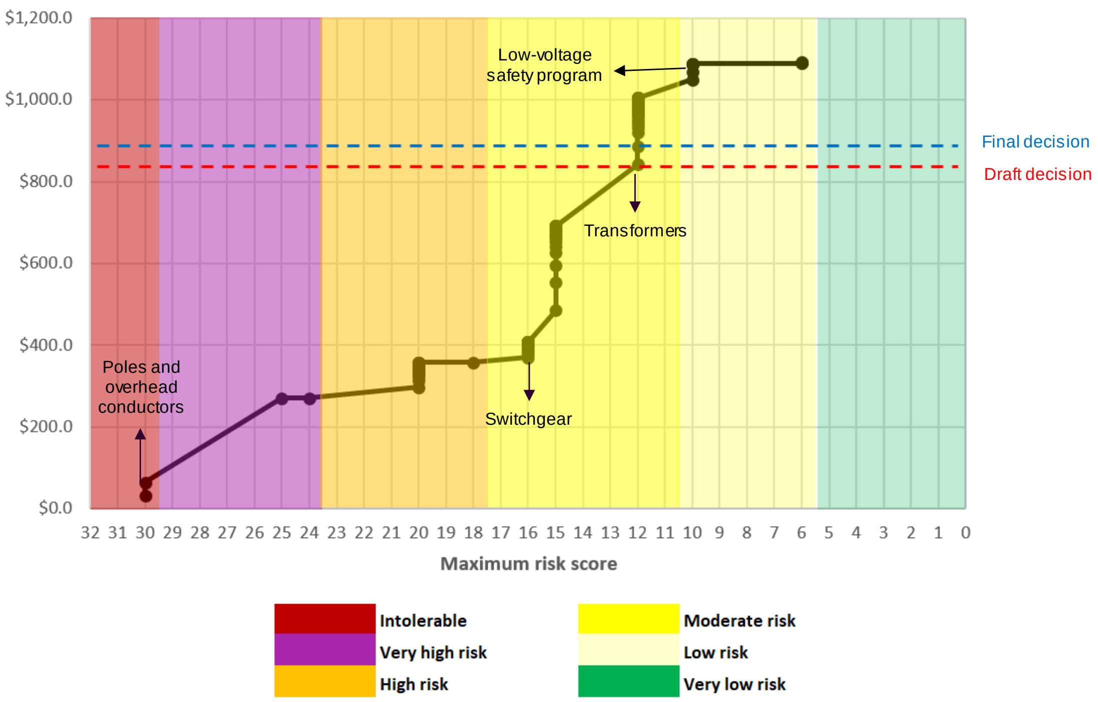
Figure A.3 plots Ergon Energy's repex portfolio (increasing repex amounts on the Y axis) against its own internal risk scores for each program and project (X axis). The chart groups repex programs and projects into qualitative risk categories, ranging from intolerable to high to very low. It indicates that a large proportion of Ergon Energy's repex forecast proposes to address moderate or low risk programs and projects.

Figure A.3 also annotates Ergon Energy's key asset groups and repex programs. Notably, its low-voltage safety program is categorised as a low risk program. The horizontal blue line indicates that our final decision forecast ($891.8 million) would provide Ergon Energy with sufficient resources to address:

- all of its intolerable, very high risk and high risk programs and projects
- the majority of its moderate risk programs and projects
- more than double its intolerable, very high risk and high risk programs and projects.

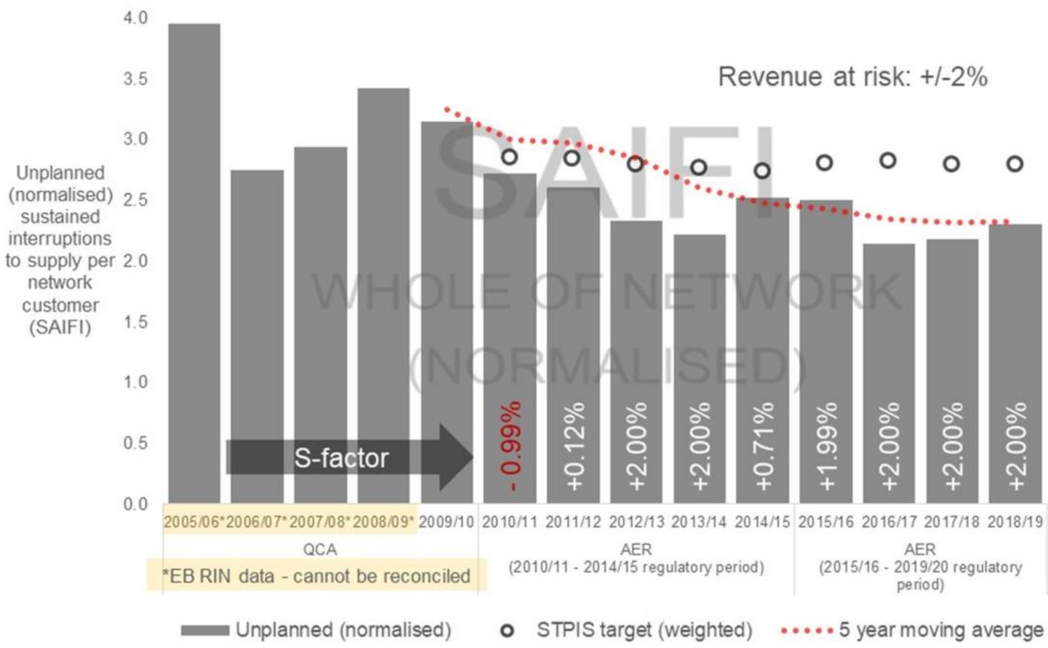
Figure A.3 – Ergon Energy's repex portfolio by risk category ($2019–20, million)



[71] Dynamic Analysis, *Technical report on Ergon Energy's revised proposal,* January 2020, p. 8.

Source: Ergon Energy's initial proposal and AER analysis.
Note: Figure A.3 presents Ergon Energy's initial repex forecast. We asked for the equivalent data for its revised repex forecast but this data was not provided.

Figure A.4 – Ergon Energy's unplanned supply interruptions



Source: Economic benchmarking and annual reporting RINs, AER analysis.

Figure A.4 highlights that, a total network level, Ergon Energy's network reliability has improved since the beginning of the 2010–15 regulatory control period. The frequency of unplanned outages has declined over this period, indicating that Ergon Energy's unserved energy risk, at a total network level, is declining over time.

This highlights that Ergon Energy has been able to improve the reliability of its network over the last nine years with its revealed capex (and by extension repex) spend. We therefore consider capex and repex forecasts that are broadly in line with this historical expenditure are likely to provide Ergon Energy with sufficient resources to at least maintain its network reliability.

Based on the information we have received, our final decision will provide Ergon Energy with sufficient expenditure to meet its safety obligations and other ongoing regulatory requirements. Its high-level network performance has not deteriorated over the past two regulatory control periods, indicated by long-term SAIFI (Figure A.4), SAIDI and asset failure measures. As a result, we do not expect there to be any significant change in performance over the forecast period given business-as-usual expenditure.

A.4 ICT capex

Information and communications technology (ICT) refers to all devices, applications and systems that support business operation. ICT expenditure is categorised broadly as either replacement of existing infrastructure for reasons due to end of life, technical obsolescence or added capability of the new system) or the acquisition of new assets for a business need.

We accept Ergon Energy's revised ICT capex forecast of $164.4 million. This revised forecast is 4 per cent higher than our draft decision of $158.4 million and 22 per cent lower than Ergon Energy's initial proposal of $210.1 million.

Ergon Energy accepted our draft decision on ICT capex subject to a minor modelling adjustment to our substitute estimate for recurrent ICT capex. We accept Ergon Energy's proposed adjustment and consider Ergon Energy's revised ICT capex forecast to be prudent and efficient.

A.5 Property capex

Property expenditure relates to the maintenance, refurbishment and optimisation of offices, operational depots, warehouses, training facilities and other specialist facilities. The indirect costs associated with property assets have been assessed as part of overheads and the costs below refer to ‘direct’ capital costs only.

Property services for both Ergon Energy and Energex are undertaken by a single entity specifically responsible for optimising and maintaining the combined property portfolio in Queensland. The property capex proposals for Ergon Energy and Energex are therefore comprised of common projects where costs have been allocated to each business.

A.5.1 Final decision

We have included $65.8 million for property capex in our substitute estimate of total capex. This is $38.0 million lower than Ergon Energy's revised proposal of $103.8 million and $9.3 million higher than our draft decision of $56.5 million. Our estimate is based on our overall view of the prudency and efficiency of Ergon Energy's proposal.

Ergon Energy has demonstrated the prudency and efficiency of the Rockhampton data centre replacement, but has not demonstrated the prudency and efficiency of three other projects. Our analysis demonstrates that Ergon Energy's base case is the most prudent and efficient option for the forecast regulatory control period for the Maryborough depot, Townsville training facility and property security projects.

Our substitute estimate includes the total $5.9 million of capex identified under the base case options for each project, rather than the proposed total of $43.3 million. All remaining capex, as proposed by Ergon Energy in its revised proposal, is included in our substitute estimate.

A.5.2 Ergon Energy's revised proposal

Ergon Energy's revised proposal includes forecast property capex of $103.8 million. This is a reduction of $24.7 million from Ergon Energy's initial proposal of $128.6 million and an increase of $47.3 million from our draft decision of $56.5 million.

Our draft decision considered some of Ergon Energy's initial property capex forecast to be prudent and efficient, with the exception of six projects. Ergon Energy has accepted our position for two of these six projects and has reproposed the other four projects. In response to our draft decision, Ergon Energy provided revised business cases and cost-benefit analyses for its proposed Maryborough depot redevelopment, Townsville training facility redevelopment, Rockhampton data centre replacement and property security projects.

A.5.3 Reasons for final decision

Our assessment of the proposed Maryborough depot refurbishment, Townsville training facility redevelopment, Rockhampton data centre replacement and property security projects is provided below.

Maryborough depot refurbishment

Ergon Energy has proposed to upgrade its Searle St depot to address building condition defects, building safety and compliance issues, and to expand the site to allow its Adelaide St office workforce and related services to be transitioned to site.[72]

While Ergon Energy's need statement has improved from its initial proposal, it has not identified any compelling needs that require it to redevelop the facility now. Ergon Energy did not undertake the project in the current regulatory control period despite the fact that it would have fallen within its capex forecast during the period, which contradicts its argument of a pressing need at this site.

Ergon Energy's cost-benefit model forecasts that the major redevelopment option will result in lower costs than its counterfactual base case option in NPV terms. It states that its base case is to “maintain the existing facilities on an ongoing basis”.[73] However, in the cost-benefit model the base case includes the costs of the proposed major redevelopment in the following regulatory control period, rather than not undertaking any major work at all. Ergon Energy provided no evidence to support this assumption.

This assumption also differs from the documentation presented in its initial proposal, which assumed major works could be deferred in perpetuity under a base case counterfactual.[74] We therefore consider the base case that has been modelled to be a deferral option, rather than a ‘business-as-usual’ (BAU) counterfactual.

We tested whether Ergon Energy's proposed major refurbishment was likely to be the lowest cost option by constructing the following alternate options:

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[72] Ergon, *Revised regulatory proposal attachment 6.039 – Business case Maryborough consolidation,* December 2019.

[73] Ergon, *Revised regulatory proposal attachment 6.039 – Business case Maryborough consolidation,* December 2019, p. i.

[74] Ergon, *Response to AER information request 2 – Property Maryborough NPV*, 18 February 2019.

- Ergon Energy's base case with the assumed major refurbishment costs removed[75] (i.e. a BAU counterfactual)
- Ergon Energy's base case with the assumed major refurbishment deferred by an additional five years (i.e. an extended deferral option).

Both of these options have a higher NPV (or lower cost) than Ergon Energy's chosen option. Therefore, Ergon Energy has not demonstrated why it must undertake this investment and our analysis demonstrates that the base case represents the best economic outcome in the forecast period. As a result, we have included the $3.0 million Ergon Energy would incur in adopting the base case in our substitute estimate.

Townsville training facility redevelopment

Ergon Energy has proposed to redevelop its Townsville training facility. It states that the drivers of the project are end-of-life assets and structural issues, workplace health and safety, effectiveness of the site for training operations (fitness-for-purpose), and disruptions to training operation.[76]

While Ergon Energy provides some descriptions of the issues, it has not presented a complete assessment to ascertain their scale and severity. For example, it has not defined or explained the criteria for a building to be assessed as ‘end-of-life’, nor has it presented evidence to support this conclusion. Similarly, Ergon Energy has not provided any information as to how many training hours were disrupted due to facility condition defects. Therefore, Ergon Energy has not provided evidence that there are material issues that need to be addressed at this site such that it must redevelop the facility.

Ergon Energy's cost-benefit model forecasts that the major redevelopment option will result in lower costs than its counterfactual base case option in NPV terms. However, similar to the base case for the Maryborough depot refurbishment project, the base case is a deferral option, rather than a business-as-usual counterfactual. This assumption also differs from the documentation supporting the initial proposal, which assumed major works could be deferred in perpetuity under a base case counterfactual.[77] This facility is also considerably younger than the corresponding Rocklea training facility.[78]

We tested whether Ergon Energy's proposed major redevelopment was likely to be the lowest cost option by constructing the following alternate options and calculating the NPV:

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75 We also allowed for same assumed capex for defect remediation and lifecycle replacement every ten years.

76 Ergon, *Revised regulatory proposal attachment 6.038 – Business case Townsville training facility*, December 2019.

77 Ergon, *Response to AER information request 2 – Property Townsville training NPV*, 18 February 2019.

78 We discuss the Rocklea training facility in Energex's final decision. The Rocklea training facility is 68 years old, while the Townsville training facility is 36 years old.

- Ergon Energy's base case with the assumed major refurbishment costs and any associated benefits removed (i.e. a BAU counterfactual)
- Ergon Energy's base case with the assumed major works deferred to when the building is 50 years old (i.e. an extended deferral option).

Both of these options have a higher NPV than Ergon Energy's chosen option.

Ergon Energy has quantified two benefits from redeveloping the site, $0.192 million per annum of operational efficiencies and $0.06 million per annum of opex savings. It has stated that the efficiency benefit is due to time savings in training delivery, which are forecast to be approximately 12 minutes for each half day of training. However, even if the training was able to be delivered faster as a result of the redevelopment, since the participants are away from their normal work locations the saved time cannot be used for any productive work. Similarly, because the lengths of the training courses are generally half a day at a minimum, the training time reduction would not create material savings for the training facilities. This is because it does not reduce the cost of the training or result in the delivery of additional training.

Overall, Ergon Energy has made improvements in supporting this project. However, the information presented does not support the proposed works as being prudent and efficient for the forecast regulatory control period. We accept the costs identified in the base case as being required if the major refurbishment were to be deferred and we have therefore included the identified $3.0 million in our substitute estimate.

Rockhampton data centre replacement

Ergon Energy proposed to replace its Rockhampton data centre, a joint operational facility with Energex. Ergon Energy has proposed to replace the data centre at an alternative existing owned site enabling cost efficiencies through property rationalisation.

Similar to the issues we have discussed above relating to the base case in the cost-benefit model, the base case for this project has been constructed as a deferral option without any supporting evidence. However, when we removed the major works from the base case, the proposed option remained materially better in NPV terms.

Overall, other than this issue, the assumptions of the cost-benefit analysis appear to be reasonable and the business case demonstrates that this project is prudent and efficient.

Property security program

Ergon Energy has proposed capex for upgrades to its non-network property physical security. Its revised forecast is $9.0 million higher than our draft decision of $1.3 million, while is $7.8 million lower than its initial proposal of $18.1 million.

Ergon Energy submitted that the primary driver of this program is safety risk mitigation. The other submitted drivers are requirements to invest consistent with security management best practices, legislation and standards, and the opportunity to reduce costs of loss through break-in and theft incidents.[79]

Ergon Energy stated that its strategy for property security is aligned against the Australian Government Protective Security Policy Framework (PSPF). It submitted that it expects that it will be mandated to comply with the Queensland Government's Protective Security Framework in the forecast period, which is based on the PSPF. However, as stated in our draft decision, Ergon Energy has not provided evidence to demonstrate why this is a reasonable assumption.

Ergon Energy states that a Security Vulnerability Risk Assessment (SVRA) was performed to determine the efficient level of investment required at each site. Our draft decision stated that there was no evidence that such analysis was undertaken in preparing the forecast. In the revised business case, Ergon Energy outlines the SVRA process it applied, which we consider to be reasonable.

We reviewed Ergon Energy's options analysis to determine if it had considered all options and we consider it to be appropriate. It has considered a base case that is to continue security expenditure at historic levels and has compared this with other options of various scale.

We reviewed the risk-cost analysis underlying the cost-benefit assessment. Overall, this analysis is a significant improvement on the analysis presented with the initial proposal. While we consider the cost assumptions to be reasonable, the risk reduction assumptions are likely to overstate the level of risk reduced by its chosen program.

Ergon Energy estimates the risk reduction benefit by calculating the difference between the estimated residual risk of undertaking its base case and the residual risk of undertaking its chosen option. In calculating residual risk for each option, Ergon Energy estimates the value of consequence from various risks occurring and multiplies these by an assumed probability of each risk occurring.

Ergon Energy assumes that the base case, which is based on historical expenditure, would not lead to any incremental risk reduction. We do not consider this assumption to be reasonable. Ergon Energy's BAU approach to property security would be to constantly identify aspects of vulnerability, and where economically prudent, implement security measures accordingly. Therefore, there would be some incremental risk reduction achieved by continuing to invest based on historical levels. By not accounting for this incremental risk reduction, Ergon Energy has overstated the risk reduction benefit of its chosen option.

To align with the ALARP principle, Ergon Energy multiplies the estimated value of consequence by disproportionality factors. However, the values chosen exceed a range we consider to be reasonable for the electricity industry. We highlighted the

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79 Ergon, *Revised regulatory proposal attachment 6.007 – Property capex summary*, December 2019, p. 5

same concerns in our repex assessment. We tested Ergon Energy's cost-benefit model by adjusting the disproportionality factors, holding all else constant. By applying lower disproportionality factors, the model showed the base case to be the highest NPV option.

We also reviewed Ergon Energy's underlying risk calculation assumptions. These assumptions were not supported by evidence and appear to be conservative, i.e. overstating the likelihood of risk consequences. For example, under its base case, Ergon Energy assumes there will be close to one serious injury every 10 years as result of trespassing. Similarly, a 40 per cent probability is assumed for a serious injury from trespassing into an adjoining high-voltage enclosure. Ergon Energy has not provided any historical evidence to show that these are reasonable assumptions.

The main risk Ergon Energy estimates it is facing is the risk that someone trespasses onto a non-network site and dies,[80] while not explaining how such a fatality would occur. It has assumed a 37 per cent probability of this consequence occurring in its base case. We searched for publically available data on the level of this risk historically.

Yearly reports[81] from the Electrical Regulatory Authorities Council provide electrical fatality data across Australia and New Zealand since 2000–01. These reports show that from 2015–16 to 2018–19, overhead lines were the only source of electricity network caused fatalities. It is also noted that since 2000–01:

- 127 of the total 130 electricity network fatalities were caused by overhead/underground lines or substations/switchyards
- 43 of the 130 of the fatalities were to the general public.[82]

Making the conservative assumption that the three fatalities not caused by overhead/underground lines or substations/switchyards were at non-network sites, it is implied that historically 2.3 per cent[83] of electricity network caused fatalities were due to non-network assets. Therefore, approximately an expected one of the 43 general public fatalities over the previous 19 years in Australia and New Zealand were at non-network sites. Therefore, a fatality at a non-network site in both Australia and New Zealand has historically been a one in 19-year event (or a near one in 20-year event).

Ergon Energy's risk assumptions imply a significantly higher fatality rate than other distributors given the relative size of its network. We do not consider this assumption to be substantiated. In addition, Ergon Energy is a predominately rural network. Facilities in rural areas are likely to have lower risk exposure than those in urban areas.

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80 Approximately 80 per cent of the total calculated risk cost is assigned to this risk.

81 https://www.erac.gov.au/erac-reports/ (accessed 26-02-2020)

82 It is shown that the trend for these fatalities has been declining over the reporting period (average of 1.4 general public fatalities per year over the previous five years compared to an average of 2.5 per year over the first 10 years of the reporting period). We have not accounted for this decreasing trend.

83 3/130.

Therefore, Ergon Energy's risk probability assumptions are not aligned with available historical data.

Overall, Ergon Energy has presented a more comprehensive evaluation of the property security management risks and costs. However, the disproportionality factors applied are excessive and the underlying risk calculation assumptions are likely to be conservative. This has resulted in an overstated risk reduction benefit for the chosen option. Our analysis demonstrates that the base case is the most prudent and efficient option for the forecast regulatory control period and we have therefore included these costs in our substitute estimate.

A.6 Other non-network capex

Other non-network capex includes fleet, plant, tools and equipment. The largest component of this category is fleet, which covers expenditure for purchasing new vehicles and related items, including mounted plant. This can be divided between light fleet (passenger and light commercial vehicles) and heavy fleet. Heavy fleet typically comprises elevated work platforms (EWPs), crane borers and other heavy commercial vehicles.

A.6.1 Final decision

We accept Ergon Energy’s revised other non-network capex forecast of $150.5 million, based on the additional information it has provided in its new fleet model.

A.6.2 Ergon Energy's revised proposal

Ergon Energy originally proposed $160.7 million for fleet, plant and equipment. We were not satisfied that this was efficient based on our investigations of efficient service lives, unit rates, the case for additional emergency vehicles, accounting for the proportion of private use, and the method applied to forecast tools and equipment. Our bottom-up changes to these assumptions resulted in a substitute estimate of $137.5 million.

Ergon Energy's revised proposal accepted that adjustments were necessary in each of these areas. The most significant differences between its new model and the approach used for our substitute estimate include:

- reversing a top-down volume reduction Ergon Energy had included in its original proposal and that our substitute estimate had retained
- more frequent replacement of some light commercial vehicles based on further consideration of kilometres travelled

- the assumption that cranes borers will require 're-trucking' after 10 years, where our substitute estimate had assumed this was not necessary.[84]

A.6.3 Reasons for final decision

Based on the information Ergon Energy has provided in its new bottom-up model, we are satisfied that its forecast reasonably reflects its efficient fleet costs. In particular, Ergon Energy has identified that some vehicles not originally identified as needing replacement do need replacing according to its criteria. In addition, we are satisfied that the costs of servicing crane borer truck bodies after 10 years are sufficiently close to replacement costs that the issue does not affect the forecast materially. Stakeholders considered that given Ergon Energy's substantial work providing new information, there is sufficient evidence to support the fleet program.[85]

A.7 Capitalised overheads

Overhead costs include business support costs not directly incurred in producing output, and shared costs that the business cannot directly allocate to a particular business activity or cost centre. The Australian Accounting Standards and the distributor's cost allocation methodology (CAM) determine the allocation of overheads.

A.7.1 Final decision

We do not accept Ergon Energy's revised capitalised overheads forecast of $682.2 million. We have included a capitalised overheads forecast of $609.9 million in our substitute estimate of total capex.

We have made the following adjustments to Ergon Energy's overheads:

- adjusted base year capitalised overheads to reflect opex overheads recovery
- adjusted output change and price change to be consistent with our opex model
- adjusted overall overheads to account for the relationship with direct capex.

A.7.2 Ergon Energy's proposal

Ergon Energy's revised capitalised overheads forecast of $682.2 million is higher than our draft decision forecast of $610.6 million. It accepted our draft decision methodology and applied the following adjustments:

- updated its 2018–19 estimated capitalised overheads to actual costs
- applied its 2020–25 CAM to derive 2018–19 base year capitalised overheads

[84] Ergon Energy, *Fleet, tools and equipment capex summary*, December 2019, pp. 2–3.

[85] Dynamic Analysis, *Technical advice to Energy Consumers Australia on Ergon Energy's revised proposal*, January 2020, p. 10.

- calculated the historical proportion of capitalised overheads to total capex
- adjusted its forecast capitalised overheads from the draft decision to reflect the higher direct capex, assuming a 25 per cent variable component of capitalised overheads.[86]

Ergon Energy then adjusted for relevant escalations.[87]

A.7.3 Reasons for final decision

Ergon Energy's capitalised overheads forecasting methodology is reasonable. It has largely adopted our draft decision methodology and included updated figures. The adjustments we have made to Ergon Energy's capitalised overheads reflect modelling adjustments to base year overheads, the rate of change and direct capex.

Base year overheads

Ergon Energy applied several base year adjustments to its actual 2018–19 capitalised overheads of $184.7 million, reducing it to $128.1 million. However, this does not include an opex corporate overheads recovery true up of $4.2 million.

In response to an information request, Ergon Energy quantified all of its base year adjustments.[88] We are satisfied that the adjustments included in this response are prudent and efficient. However, Ergon Energy did not account for a corporate overheads recovery true-up. We have accounted for this true-up in opex and this results in a reduction to Ergon Energy's 2018–19 capex included in its roll forward model.

A change in overhead allocation and Ergon Energy using 2018–19 as its base year solely drives the reduction in 2018–19 capex. We have therefore adjusted this by reducing base year overheads by $4.2 million to $123.9 million. This reduction accounts for a $21.2 million reduction in forecast overheads for the 2020–25 regulatory control period. Attachments 2 and 6, respectively, discuss more information on actual RAB and opex adjustments.

Rate of change adjustment

We have updated the rate of change to be consistent with our opex rate of change. Ergon Energy noted that its rate of change for capitalised overheads is based on the opex rate of change[89] and its revised proposal reflects updated figures for relevant escalations.[90]

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86 This approach is consistent with the methodology we have used to set a substitute estimate of capitalised overheads in our recent decisions.

87 Ergon Energy, *Revised regulatory proposal,* December 2019, p. 32.

88 Ergon Energy, *Response to information request 73,* January 2020.

89 Ergon Energy, *Ergon Energy regulatory proposal 2020–25,* January 2019, p. 79.

90 Ergon Energy, *Ergon Energy revised regulatory proposal 2020–25,* December 2019, p. 32.

We have made the following adjustments to capitalised overheads:

- updated the output change to be consistent with our opex output change inputs, including an update to output change measures and weights for the output change models.
- updated the price change to be consistent with our opex price change to reflect updated labour price escalations.

This reduces the average capitalised overheads rate of change from 1.4 per cent per annum to 0.6 per cent per annum. This also increases the price change from 0.5 per cent per annum to 0.6 per cent per annum. We discuss the opex rate of change in more detail in attachment 6. The net impact of updating these modelling inputs is a $15.8 million reduction in Ergon Energy's capitalised overheads.

Direct capex adjustment

There is a direct relationship between the quantity of direct capex and capitalised overheads. As our direct capex substitute estimate is lower than Ergon Energy's revised capex forecast, we would expect Ergon Energy to require less overheads for this lower volume of work. It follows that we would expect some reduction in the size of capitalised overheads.

Consistent with our draft decision[91] and Ergon Energy's revised proposal,[92] we have adopted a 75 per cent fixed and 25 per cent variable ratio. As our direct capex substitute estimate is 21 per cent lower than Ergon Energy's revised proposal, this results in a 5 per cent reduction in Ergon Energy's capitalised overheads. This adjustment is applied after the base year and rate of change adjustment.

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91 AER, *Ergon Energy draft decision,* October 2019, p. 76.

92 Ergon Energy, *Ergon Energy revised proposal,* December 2019, p. 32.

Shortened forms

Shortened form	Extended form
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP14	Consumer Challenge Panel (sub-panel 14)
CESS	capital expenditure sharing scheme
DER	distributed energy resources
ICT	information and communications technology
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value
RAB	regulatory asset base
repex	replacement expenditure
RIN	Regulatory information notice
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
STPIS	service target performance incentive scheme