Revised Regulatory Proposal for the 2020-25 Regulatory Period Internal Operating Expenditure Forecasts

December 2019

Part of the Energy Queensland Group

Executive Summary

Key Messages

- We have accepted the Australian Energy Regulator's (AER's) draft decision opex forecasts for the 2020-25 regulatory control period of $1,806 million for Energex and $1,834 million for Ergon Energy, including debt raising costs (DRC) (or 1,775 million and $1,806 million, respectively, excluding DRC)
- We also developed internal forecasts based on updated inputs of $1,909 million for Energex and $1,958 million for Ergon Energy including DRC (or $1,888 million and $1,949 million, respectively, excluding DRC) – these highlight:
- Consistent with the Draft Decisions, the internal forecasts
    - Retained the AER's preferred Base-Step-Trend (BST) approach to developing our revised forecast opex, including by updating its draft decision forecasting model for updated inputs
    - Forecast our debt raising costs by applying the AER's methodology, updated for the latest Chairmont data
- Our actual opex in the 2018-19 year was:
    - For Energex was less than we estimated in the Regulatory Proposal, and is also less than what the AER's draft decision approved as efficient. When tested against the econometric models considered in the AER's 2019 Annual Benchmarking Report, our base year remains efficient.
    - For Ergon Energy more than we estimated in the Regulatory Proposal, and even after normalising for our higher than average emergency response costs in responding to sever weather, it is higher than what the AER's draft decision approved. When we normalise our base year for these weather events and test against the econometric models considered in the AER's 2019 Annual Benchmarking Report, our base year remains efficient.
- Our January 2019 Regulatory Proposals included opex reduction measures intended to support customer affordability whilst ensuring these can be sustainably achieved without service degradation. We are proposing to change our approach to ensure we are not exceeding our affordability commitment at the expense of the safety, security or sustainability of our network.
- Included in our internal opex forecasts are our transparent and achievable commitments to further productivity savings. These comprise an 0.5% annual productivity factor as well as negative step changes that reflect the quantified benefits in our business cases for our capex investments in ICT and property, of $37 million for Energex and $37 million for Ergon Energy over the 2020-25 period.

Contents

1. Background and purpose

Our proposed SCS operating expenditure (opex) for the 2020-25 regulatory control period is $1,806 million for Energex and $1,834 million for Ergon Energy, including DRC. This is the same amount we submitted in our January 2019 Regulatory Proposals and that was accepted by the AER in its Draft Decisions. [1]

Although we have adopted those opex forecasts in our Revised Proposals for both businesses, we have also developed internal forecasts.

This attachment explains the basis of those internal forecasts for Energex and Ergon Energy and how these respond to the AER's draft decision. It is supported by and should be read in conjunction with our opex models (Attachments *EGX 7.006* and *ERG 7.006*) and attached independent expert reports from Frontier Economics (Attachment *EGX ERG 7.005*) and BIS Oxford (Attachments *EGX ERG 7.003* and *EGX ERG 7.004*) and a model review by PwC (Attachment *EGX ERG 7.008*).

1.1 Approach

At a summary level, this attachment steps through how we have forecast opex for both Energex and Ergon Energy by:

- Starting with the AER's alternative forecast models, as they reflect its reasonable view as to what is efficient for Energex and Ergon Energy
- Updating these for more recent data and input assumptions, including actual 2018-19 opex, updated labour escalator forecasts, updated demand forecasts, and capex business case-linked opex savings
- Applying base year adjustments to actual opex of each network (e.g. accounting adjustments to both, and an emergency response normalisation to Ergon Energy)
- Testing the benchmark efficiency of our resulting base years for each network.

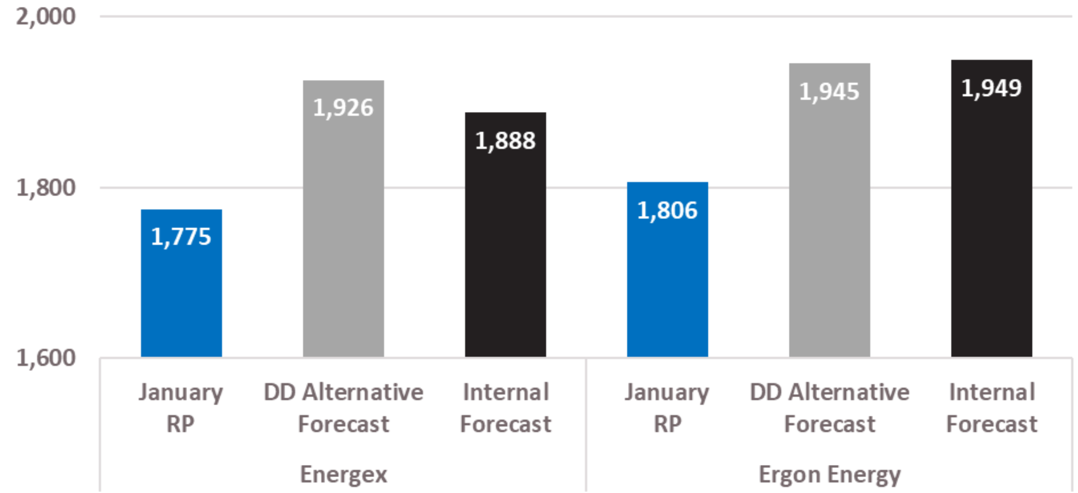
Although our opex forecasts also include estimated debt raising costs and we have continued to apply the approach and assumptions used by the AER in the Draft Decisions, this attachment does not cover them in any detail.

1.2 Operating expenditure forecast

Applying the above approach, forecast opex for Energex and Ergon Energy over the 2020-25 period is $1,888 million and $1,949 million excluding DRC or $1,909 million and $1,968 million including DRC, respectively, as shown in Figure 1. These forecasts are $113 million and $143 million higher than the equivalent forecasts in the January 2019 Regulatory Proposals, which largely reflect reductions to the proposed management stretch targets that were previously included.

[1] Unless otherwise stated, all financial values reported in this attachment are in dollars as at 30 June 2020 – which is referred to throughout as 'Real $2020' – and for standard control services (SCS).

Figure 1 Revised Regulatory Proposal opex forecasts ($M, Real $2020)



Note: the opex forecasts shown here exclude debt raising costs. Including DRC, the values are (from left to right) $1,806 million, $1,947 million, $1,909 million, $1,835 million, $1,964 million, and $1,968 million.

1.3 Incentives

The AER's draft decision noted the inherent interrelationship between our opex base year used for the purposes of forecasting opex, and our efficiency benefit sharing scheme (EBSS) carryover amounts from the 2015–20 control period.[2]

We have updated the AER's calculations of EBSS revenues in the Draft Decision to reflect:

- audited actual opex in 2018-19
- emergency response normalisation for Ergon Energy in 2018-19 to remove one-off costs
- the latest forecast of inflation for 2019–20 from the Reserve Bank of Australia (RBA).

As a result of these updates, our rewards changes from the Draft Decision as set out in Table 1. Further detail is provided in Chapter 9 of the Revised Regulatory Proposal.

Table 1: EBSS ($M, Real $2020)

	Draft Decision	Internal Forecasts
Energex EBSS carryovers	24.31	68.22
Ergon Energy EBSS carryovers	157.63	193.93

2 AER Attachment 8, p.8-8 stated: "For these reasons, our decision on how we will apply the EBSS to Ergon Energy has a strong interrelationship with our decision on its opex (see Attachment 6). We have careful regard to the effect of our EBSS decision when making our opex decision, and our EBSS decision is made largely in consequence of (and takes careful account of) our past and current decisions on Ergon Energy's opex."

2. Background

This section outlines how we initially forecast opex in our January 2019 Regulatory Proposals, the AER's feedback in the draft decisions, and feedback we have received from our customers and stakeholders.

2.1 Initial Regulatory Proposals

Our January 2019 Regulatory Proposals forecast total opex (including debt raising costs) for Energex of $1,805.8 (real $2019-20) and for Ergon Energy of $1,834.59 (real $2019-20). These forecasts were derived from a base, step and trend, except for our debt raising costs. This is consistent with the approach that we proposed in our Expenditure Forecasting Methodology that was submitted to the AER on 29 June 2018 and the AER's preferred approach for forecasting opex, as detailed in its Expenditure Forecast Assessment Guideline.

The base step and trend approach involves forecasting opex at an aggregate level, rather than preparing individual forecasts for each category of opex. It involves the steps set out in Table 2, which also explains how we forecast these in our January 2019 Regulatory Proposals.

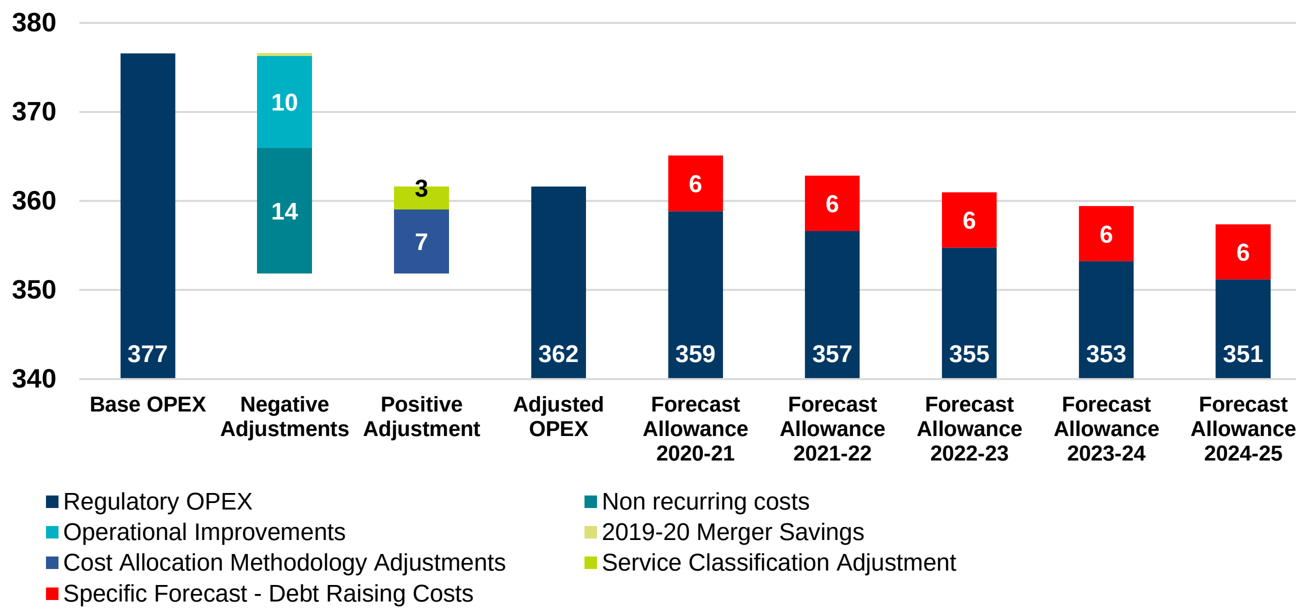
Table 2: Our Regulatory Proposal forecasting method and inputs

Forecasting step and input	Regulatory proposal approach
Nominating a base year	We nominated 2018/19 as our base year and provided an estimate of this year's spend given that we were only part way through it at the time of submission.
Applying adjustments to remove non-recurrent and other expenditure from the base year	We applied base year adjustments to account for: 2019/20 merger savings, operational improvements (redundancies and restructuring), non-recurrent costs (change fund), CAM adjustment and service classification adjustment. We also included the standard final year adjustments that are applied automatically by the opex model commonly used by the AER that were used to forecast Energex's and Ergon Energy's opex.
Applying rate of change adjustments to the adjusted base year opex for: • **Output trend** • **Price trend** • **Productivity trend**	For output growth trend, we applied the output change measures and respective weightings in the Economic Insights report released with the AER's 2018 benchmarking report, including for the impact of economies of scale. The four output growth measures were customer numbers, circuit length, ratcheted maximum demand, and energy. For price growth trend, we started with the average of the real labour escalator forecasts from BIS Oxford and Deloitte Access Economics (DAE), being 0.85% on average per year over the 2020-25 regulatory control period. We commissioned BIS Oxford to provide us with real labour escalator forecasts and adopted the DAE forecasts used by the AER in its draft Distribution Determination for the NSW distributors, expecting that the AER will commission DAE labour forecasts for Queensland in due course. We then applied a reduced price growth of 0.26% on average per annum to reflect our management commitment to improve our program of works by 3% over the 2020-25 regulatory control period. This was forecast to be achieved by the digitisation of our business processes, delivering improved work scheduling and improved corporate processes. For productivity savings trend, we proposed a positive productivity saving based on the Energy Queensland top-down management initiative of 10% total indirect cost savings, and other targeted cost reductions, which were forecast to result in an overall productivity saving of 1.72% pa for Energex and 2.58% pa for Ergon Energy.
Forecasting step changes	We did not forecast any step changes, either positive or negative.
Estimating benchmark debt raising costs	We forecast our debt raising costs on a benchmark rate of 8.05 basis points.

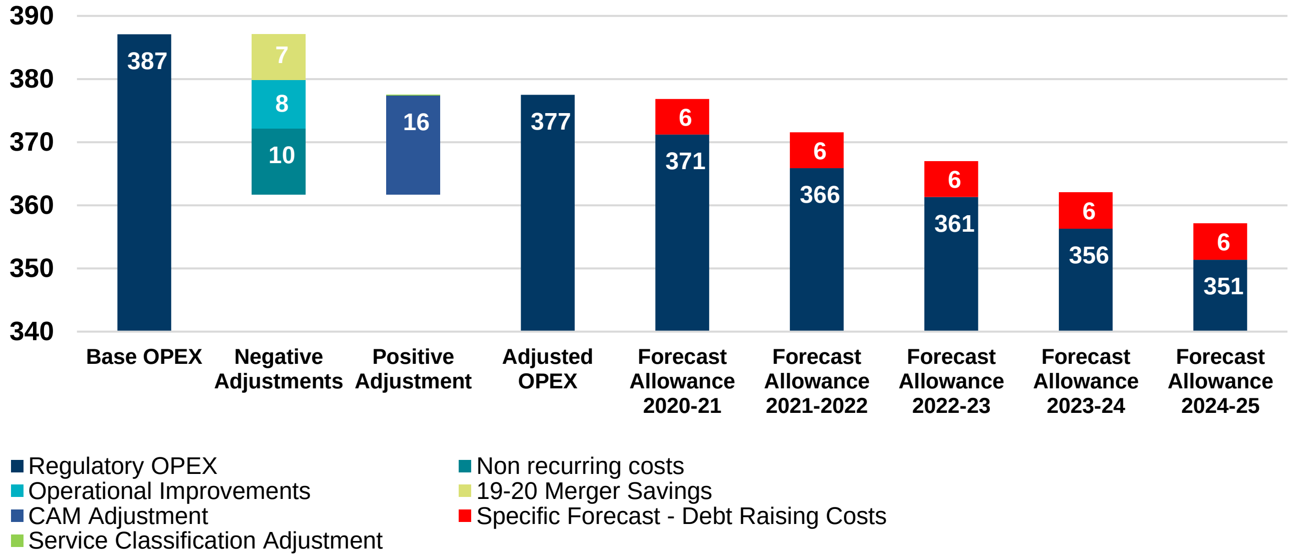
The forecasts resulting from our Regulatory Proposal forecasting approach shown in Figure 2. Both charts show how the top down management commitments we built into our negative base year adjustments and ambitious wage price and productivity savings resulted in a forecast that was materially below what we currently incur.

Figure 2 Regulatory Proposal opex forecast ($M, Real $2020)[3]

Energex



Ergon Energy



3 The Energex chart is taken from Figure 19 of Energex's January 2019 Regulatory Proposal; while the Ergon Energy chart is taken from Figure 18 of its January 2019 Regulatory Proposal.

2.2 Draft decisions

The AER's Draft Decisions developed alternative forecasts to test the efficiency of our proposed opex. It based the alternative forecasts on our estimated 2018/19 base year data because our actual data was not available at the time.

Because our proposed forecasts were significantly below its alternative forecasts, the AER's Draft Decisions accepted our proposed forecasts.

Notwithstanding that acceptance, the AER's alternative forecasts departed from our proposed base, step and trend inputs in a number of ways, and the AER provided specific feedback on what it expected us to provide by way of additional justification in our revised proposals if we were to maintain our approach and inputs.

Key themes in the AER's feedback included:

- Its concerns raised about the proposed base year adjustments, including information shortcomings in our ability to reconcile the accounting elements of these to their satisfactions, and a view that the one-off cost adjustments were actually recurrent costs required in future
- Observation that while Energex benchmarked efficiently, the benchmarking assessment of Ergon Energy using the AER's new approach to operating environment factor (OEF) adjustments led it to consider Ergon Energy's base year was 'borderline'
- Concerns that notwithstanding its requests for further details from us about how we would deliver them, it had reservations our ability to deliver the ambitious top-down management savings because these could not be traced to identified savings in our program of work.

Attachment 6 to the AER's Draft Decisions set out its specific feedback on our opex forecast at an input parameter level which we have summarised in Table 3.

Table 3: AER feedback

Forecasting input	AER draft decision approach and feedback
Base year	Accepted Energex's and Ergon Energy's estimated 2018/19 base opex in its alternative forecast.
Base year adjustment – negative	The AER did not apply our negative adjustments in its alternative forecast given concern that these were not one-off costs and are expected to continue to be incurred in the next regulatory period.
Base year adjustment – CAM	The AER did not apply the positive CAM and accounting adjustments due to reconciliation concerns. It set out the information it requires to explain these.
Base year adjustment - Service classification	The AER accepted the minor positive service classification change for emergency recoverable works, a change that it has also made for other distributors.
2018-19 to 2019-20 Increment	The AER accepted this adjustment, which is calculated automatically within its opex model.
Output growth	The AER updated output growth factors (using RIN numbers) which lowered the output growth.
Price growth	The AER applied its consultant's (DAE) escalations, without our BIS escalators or our proposed 3% (over 5 years) labour productivity top-down savings.
Productivity growth	The AER applied its standard 0.5% productivity adjustment without our further top-down savings.
Step changes	The AER accepted our proposal to apply no step changes, but stated that it expected our revised forecasts to account for our capex project opex savings.
Debt raising costs	The AER applied updated debt raising costs benchmarks reflecting the latest Chairmont data.

2.3 Stakeholder feedback

In addition to their valuable feedback on our draft plan and involvement in our pre and post lodgement engagement, six stakeholders made submissions to the AER on Energex's and Ergon Energy's opex proposals.[4] Table 4 summarises these responses (as presented in the AER's Draft

[4] These included Consumer Challenge Panel (CCP14), the Queensland Council of Social Services (QCOSS), National Seniors Australia, Origin Energy, the Energy Consumers Australia (ECA)—supported by a report from Dynamic Analysis, and the Queensland Government's Electrical Safety Office.

Decisions) and outlines how we have responded to each issue, and references where this is explained in this document.

Table 4: What we heard and how we responded

Issue	What we heard	How we responded in this attachment
Choice of base year and assessment of efficient base opex	CCP14 sought a better understanding of how the opex related to legacy information and communication technology (ICT) assets (previously owned by SPARQ Solutions (SPARQ opex) in the 2015–20 period) is accounted for in the base year.[5] CCP14 also identified Ergon Energy's base opex assessment as an area of key concern where the best interests of customers may not be evident.[6] QCOSS stated that Energex's benchmarking results indicate Energex's base opex may be relatively inefficient and needs to be adjusted for the inclusion of SPARQ opex.[7] QCOSS stated Ergon Energy's benchmarking results indicate Ergon Energy's base opex may be relatively inefficient.[8] The ECA also questioned whether Energex and Ergon Energy's performance in the midrange of the AER's opex benchmarks is justified, and whether customers should expect the Energy Queensland networks to achieve deeper efficiencies.[9] The ECA and the consultants, Dynamic Analysis, were not convinced that Energy Queensland's environmental and operating context justified higher costs relatively to its peers.[10] Dynamic Analysis argued it is up to the networks to quantitatively demonstrate how their operating and environmental factors lead to higher costs structures.[11] Dynamic Analysis also noted there is no evidence of what the negative base adjustments specifically relate to, but recognised Energy Queensland's efforts to do the right thing by excluding non-recurrent costs.[12] National Seniors Australia also argued that Energex (Ergon Energy), as part of Energy Queensland, is not pursuing opportunities with Ergon Energy (Energex) to share costs to reduce operating costs.[13]	The SPARQ adjustment reconciliation information requested in the AER's Draft Decisions is set out in 4.5 to this attachment. Updated benchmarking and OEF analysis (see Appendix 2 and Attachment *EGX ERG 7.005*) confirms that Energex's and Ergon Energy's base year opex is efficient. This is explained in section 4.3. Our updated base year for each network reflects application of the AER-approved cost allocation methods (CAMs) that account for a fair and compliant sharing of costs across the merged EQ group. Appendix 1 to this attachment explains how that correct application has been verified.
Productivity growth	Whilst CCP14 welcomed Energex and Ergon Energy offering additional productivity growth, they raised concerns about the reliance on ICT expenditure to underpin this productivity growth.[14] They argued it would be beneficial to see a clearer linkage between ICT investment and productivity improvement.[15] They also noted the 1.72 and 2.58 per cent per year productivity improvement figure proposed by Energex and Ergon Energy respectively had not been derived clearly or in detail.[16] Dynamic Analysis noted Energex and Ergon Energy should be commended for embedding the savings from their new digital strategy into its opex forecasts.[17]	Our revised forecast adopts both the AER's productivity factor (explained in section 5.3) as well as those additional efficiency savings that we have business case plans for achieving including from our planned ICT and property investments (explained in section 6).
Output growth / labour price growth	Origin Energy encouraged the AER to test Energex's price and output growth forecasts.[18] Dynamic Analysis noted that while forecast growth in energy volumes and customer numbers are higher than actuals in the 2015–20 period, the overall output growth forecast appears reasonable.[19]	We have updated our output factors for our updated demand, energy and customer number forecasts. This is explained in section 5.1
Step changes	CCP14 was pleased to observe the absence of step changes.[38]	We have applied only negative step changes for quantified savings arising from our planned ICT and property investments. This is explained in section 6.

5 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 13.

6 CCP14, Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals, May 2019, p. 5.

7 Queensland Council of Social Services, *QLD electricity distribution determinations – Energex and Ergon 2020 to 2025, QCOSS Submission: AER Issues Paper*, May 2019, p. 8.

8 Queensland Council of Social Services, QLD electricity distribution determinations – Energex and Ergon 2020 to 2025, QCOSS Submission: AER Issues Paper, May 2019, p. 8.

Issue	What we heard	How we responded in this attachment
Bushfire risk and vegetation management	The Electrical Safety Office noted that Energex and Ergon Energy's proposal did not include enough detail on these areas to make an informed comment.[39]	We are committed to achieving best practice asset management strategies to ensure the safe and reliable operation of our networks. This includes development and applying bushfire mitigation strategies (set out in our Bushfire Risk Management Plan) that provide a specific, targeted, measurable and costed approach. Critically, we must ensure that our assets are managed to minimise the risk of bushfires to the network, maintain customer supply reliability and ensure a high level of safety for the community during times of bushfire.

Since the draft decision we have continued to engage with our customers:

- On 16 October we presented to our RP-TSS Working Group on the AER's draft decision, our actual base year outcomes and sustainability challenges we face in achieving the initial top-down affordability commitments in our January Regulatory Proposals
- On 14 November we engaged with our RP-TSS Working Group about our planned RRP response. This included updating on:
  - the sustainability and affordability considerations affecting our opex forecasts
  - our base year 2018-19 outcomes and approach to emergency response normalisation for Ergon Energy, and approach to testing how we benchmark for efficiency
  - our revised approach to step and trend inputs, and ensuring our productivity and negative step change reflect sustainable and realisable benefits.

Amid this engagement we received feedback about how we should approach normalisation for severe weather. Suggestion was made that our ten-year normalisation should consider excluding 2010-11 year which was affected by floods and Cyclone Yasi.

We considered this, and elected not to adjust for that year, because it represents the inherent volatility risk we face here in Queensland. We remain exposed to our emergency response expenditure being persistently higher than the historical average, even with 2010-11 included. For example, in four of the last five years we've been above the ten-year average for regional

9 Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p. 15.

10 Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p.15; Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 6.

11 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 27.

12 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 32.

13 National Seniors Australia, *Response to AER Issues Paper: Qld electricity distribution determinations, Energex and Ergon Energy, 2020 to 2025,* May 2019, p. 4.

14 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 8.

15 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 13.

16 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 13.

17 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 48.

18 Origin Energy, *Letter to Mr Sebastian Roberts RE: QLD Regulatory Proposal 2020-25*, May 2019, p.2.

19 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 34.

Queensland and the whole state is enduring its earliest and most severe bushfire season on record this year.

3. Overall Approach

Our Revised Regulatory Proposals have retained the base, step and trend (BST) method. To do this, we have started with the opex models used by the AER in its Draft Decisions to develop its alternative forecasts for each network. Although the AER ultimately did not use these models to set the Draft Decision opex allowances, we consider them a reliable starting point.

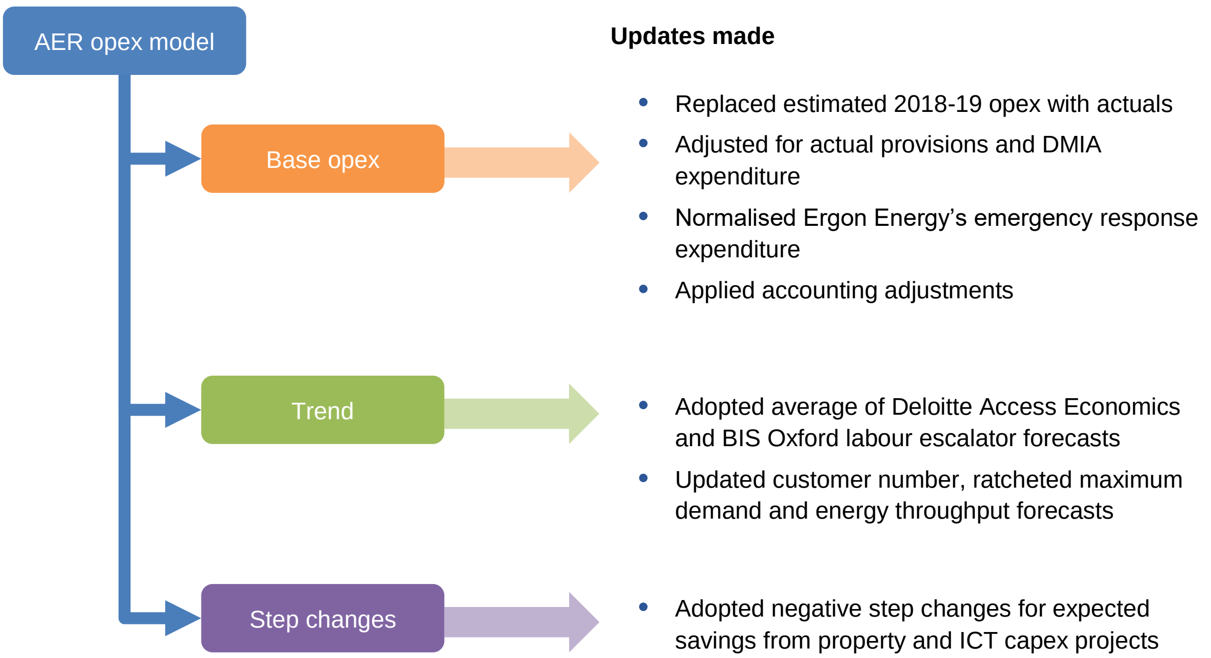
We then made several adjustments – which we explain in the following section – including to update for actual 2018-19 revealed opex, revised demand forecasts, and labour escalators. We also added negative step changes for identified savings from our property and ICT capital expenditure.

In adopting this approach, we have consciously wound back the ambitious savings and targets included in our January 2019 Regulatory Proposals so that we do not undermine the opex outcomes that benefit customers. This is discussed further in section 3.2.

3.1 Summary

We have forecast opex for both Energex and Ergon Energy using the BST method, starting with the opex models used by the AER in its Draft Decisions.[20] We amended the base, step and trend components of the AER models as summarised in Figure 3 to determine those forecasts.

Figure 3 Opex forecasting approach



In large part, the changes made were to replace estimates with actuals (see section 4.1) or more recent demand forecasts (see section 5.2).[21] We also accounted for the increased storm costs in 2018-19 experienced by Ergon Energy by replacing its emergency response expenditure with a 'normalised' historical average (see section 4.2 and Appendix 3).

[20] Australian Energy Regulator, October 2019, *AER - Energex 2020-25 - Draft decision - Metering Opex - October 2019.xlsb*; and Australian Energy Regulator, October 2019, *AER - Ergon Energy 2020-25 - Draft decision - Metering Opex - October 2019.xlsb*.

[21] In doing so, we corrected for an overstatement of Ergon Energy's reported opex for 2018-19. We discuss this further in Appendix 4.

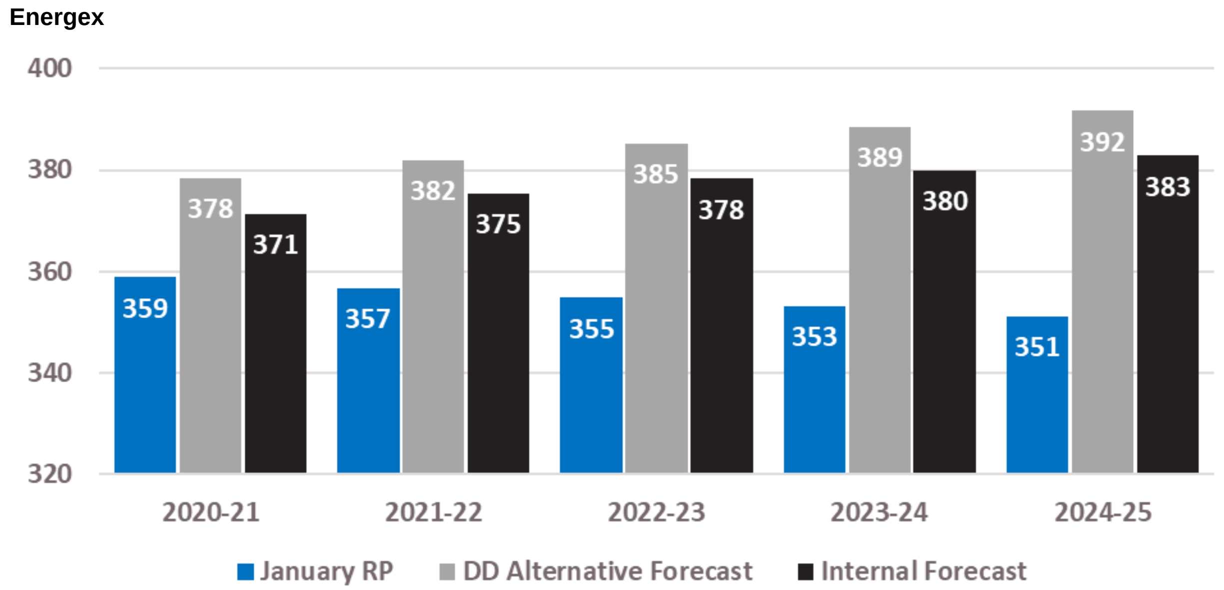
Our internal forecasts also respond to the AER's Draft Decisions by:

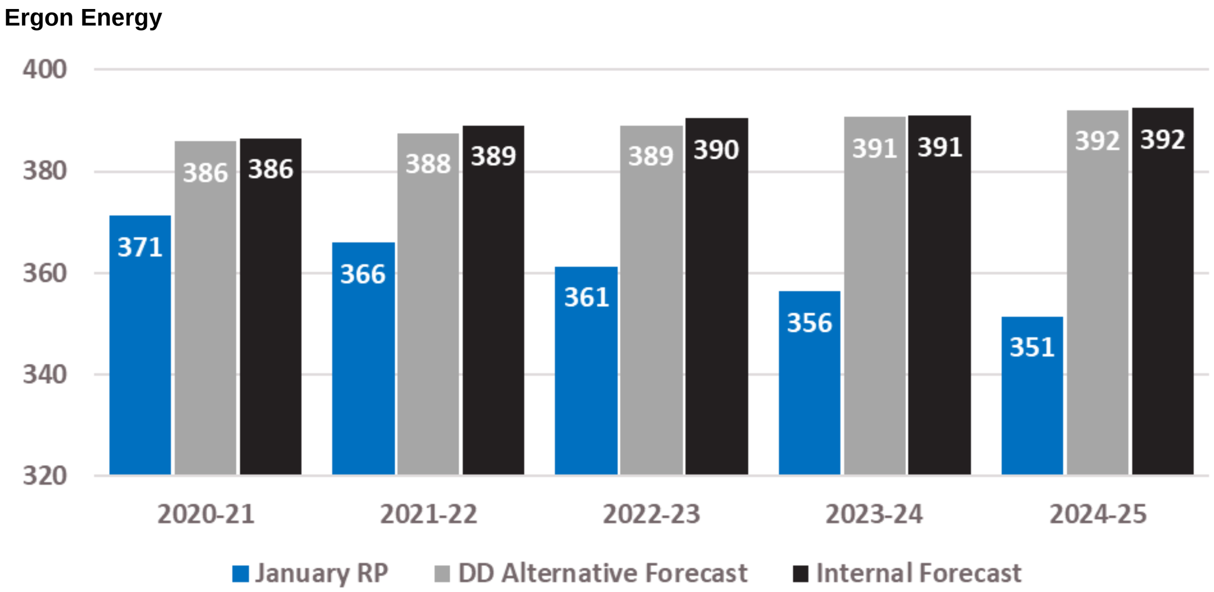
- Updating and providing further information to support accounting adjustments to base 2018-19 opex (see section 4.5 and Appendix 1), and
- Adopting negative step changes for savings expected from property and ICT capital projects that we are proposing (see chapter 6).

Our main departure from the AER's alternative forecasts was to continue with the AER's past practice of using an average of Deloitte Access Economic (DAE) and BIS Oxford labour escalator forecasts, rather than rely on DAE's forecasts only as the AER proposed in its Draft Decisions. We explain why in section 5.1

Applying the above approach led to the revised forecasts shown in Figure 4, compared to those from the January 2019 Regulatory Proposals and the AER's alternative forecasts. Importantly, Energex's RRP opex is noticeably *below* the AER's alternative forecast, while Ergon Energy's RRP is *closely aligned* with the AER's alternative forecast.

Figure 4 Revised opex forecasts ($M, Real $2020, excluding debt raising costs)





3.2 Efficiencies and sustainability

Our Regulatory Proposals included several affordability measures to support price reductions to our customers. Among these were ambitious commitments to lower our operating, labour and overhead costs materially below what we currently incur.

The risk of achieving the operating cost savings was questioned by the AER, Consumer Challenge Panel (CCP) and other stakeholders during their reviews of our Regulatory Proposals. Our experience in actual 2018-19 costs discussed in chapter 4 and further analysis of quantified savings achievable through our capex business cases discussed in chapter 6 indicate that this concern has some basis.

In response to this feedback, EQL has reconsidered including such top-down savings without quantified plans for achieving these. Especially now that our affordability commitment will already be outperformed, and there is much higher risk to our business' sustainability should either the savings not be realised in a timely manner, or increasingly severe weather events transpire during the period.

As a result, our Revised Regulatory Proposals now include:

- only those efficiency savings (in the form of negative opex step changes) for which we can transparently show measures to deliver them – see chapter 6, and
- the AER's 0.5% industry-wide productivity savings – see section 5.3.

4. Base Opex

Our base opex for both Energex and Ergon Energy start with our actual 2018-19 revealed expenditure,[22] and then adjust this for:

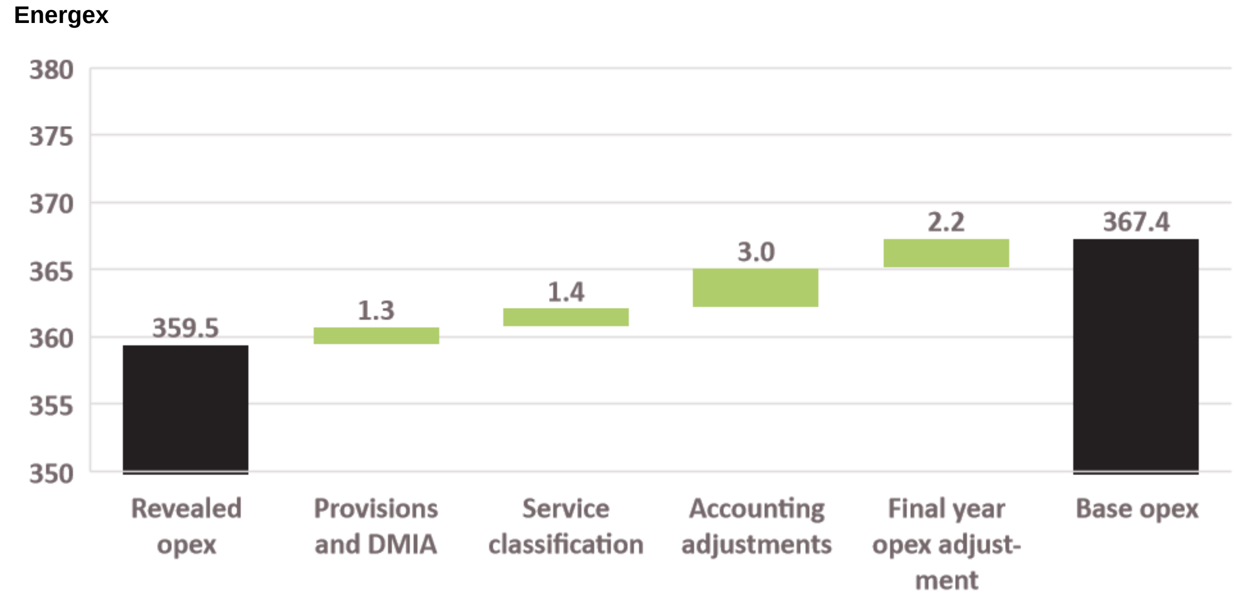
- Provisions (as commonly applied by the AER)
- Service classification changes, and
- Accounting adjustments.

For Ergon Energy, base opex was also reduced to reflect a normalised level of emergency response expenditure, which was higher due to abnormal storm activity in 2018-19.

We also tested the efficiency of actual 2018-19 revealed expenditure using the benchmarking techniques that the AER used in its draft decisions, finding that both networks' revealed opex was efficient.[23]

Figure 5 shows how the adjustments affected base opex for both networks. Each adjustment is explained further below.

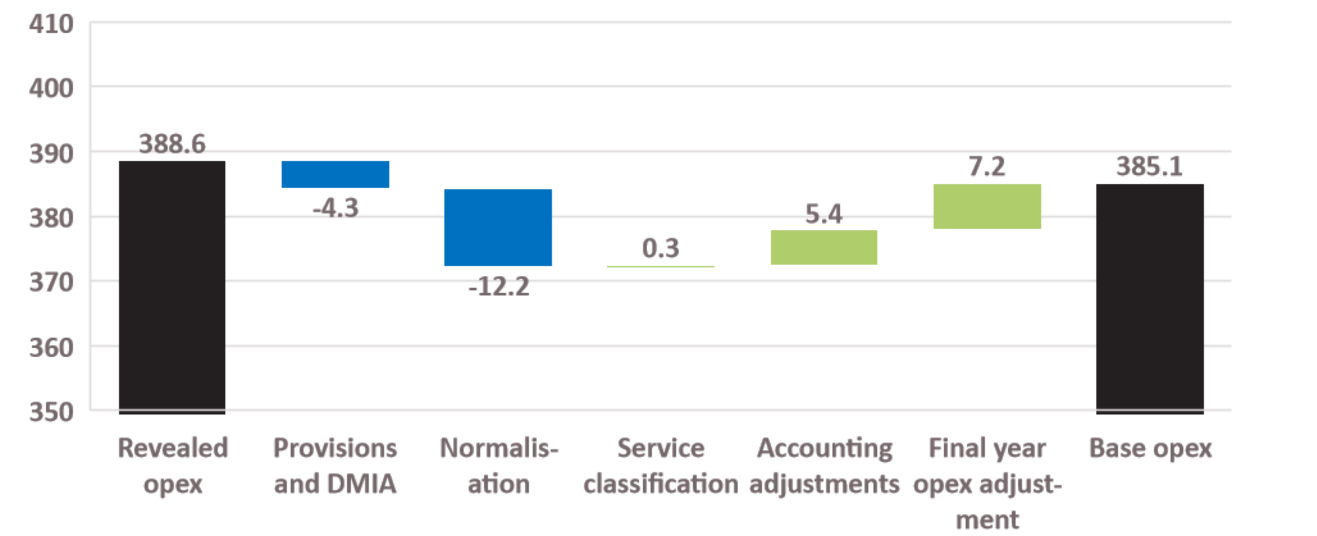
Figure 5 Base opex ($M, Real $2020)



22 For Ergon Energy, we have corrected the publicly reported actual standard control services opex for 2018-19 of $391.69 ($nominal), reducing it by $12.56 million ($nominal) to correct for an overstatement of overheads, giving $379.12 million ($nominal) or $388.63 (Real $2020). The correction is explained further in Appendix 4.

23 For Ergon Energy, we assessed the efficiency of revealed 2018-19 opex after normalising emergency response expenditure.

Ergon Energy



4.1 Revealed 2018-19 opex

Revealed opex for both networks was sourced directly from the 2018-19 regulatory information notice (RIN) responses, which reflects our most recent actual expenditure of $359.45 million for Energex and $388.63 million for Ergon Energy.[24]

Relying on actual expenditure as a starting point:

- Helps ensure that all current actual costs are captured, and
- Is consistent with the AER's expectations – set out in the Draft Decisions – that estimated opex for 2018-19 would be replaced with actual opex.[25]

Consistent with other AER decisions, revealed opex was adjusted to remove any movement for provisions and DMIA expenditure. These adjustments – of a $1.26 million increase for Energex and a $4.27 million reduction for Ergon Energy – were also sourced from the RIN responses. [26]

Unsurprisingly, the revealed *actual* 2018-19 opex for both networks differs from the estimates used in the January 2019 Regulatory Proposals (and the AER Draft Decisions that relied on them), as summarised in Figure 6. Energex's opex was noticeably lower, while Ergon Energy's was noticeably higher. As explained in section 4.2, Ergon Energy's actual opex has been adjusted down by $12.16 million to normalise emergency response expenditure.

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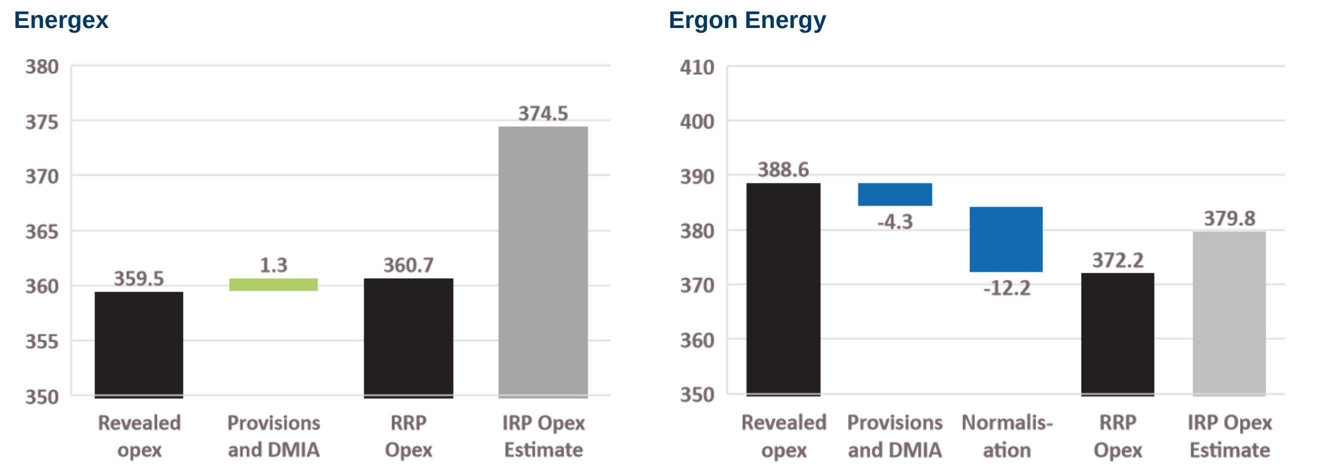
24 Energex's revealed opex was $350.66 million, in nominal dollars. Ergon Energy's revealed opex was $379.12 million, in nominal dollars, determined as the $391.69 million reported in Ergon Energy's 2018-19 RIN response less the $12.56 million overhead recoveries true-up adjustment discussed in Appendix 4. Both values were adjusted to dollars as at June 2020.

25 See, for instance, Australian Energy Regulator, October 2019, *Draft decision*, *Ergon Energy Distribution Determination 2020 to 2025*, *Attachment 6 Operating expenditure*, footnote 74.

26 Energex's movement in provisions was negative $1.60 million and DMIA expenditure was positive $0.38 million, or negative $1.23 million in total, in nominal dollars. Ergon Energy's movement in provisions was $3.72 million and DMIA expenditure was $0.44 million, or $4.17 million in total, in nominal dollars. Both sets of values were adjusted to dollars as at June 2020.

Figure 6 Actual vs estimated 2018-19 expenditure ($M, Real $2020)



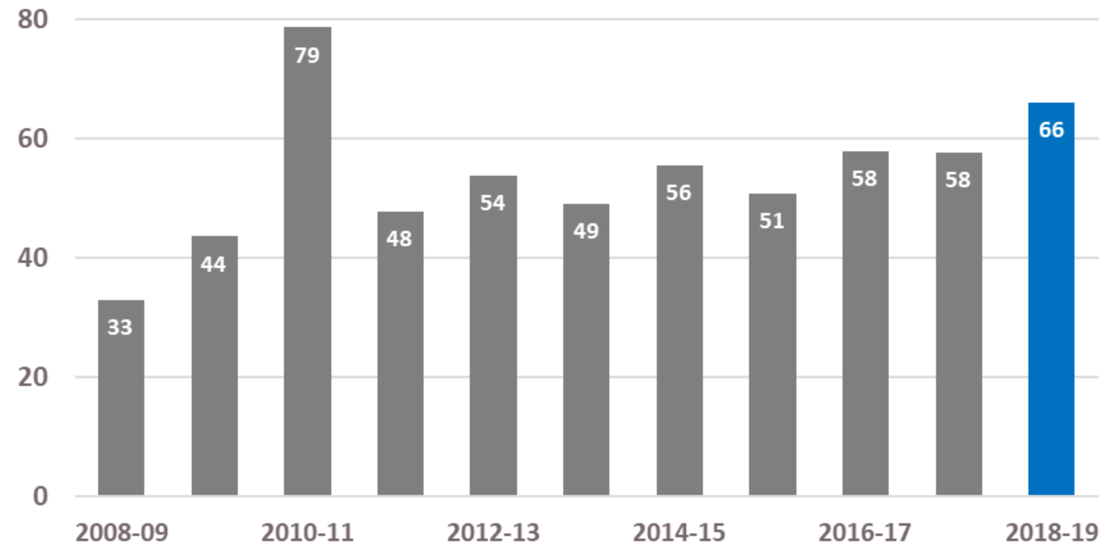
Note: the vertical axes have been curtailed to make the comparisons easier.

4.2 Ergon emergency response normalisation

Ergon Energy incurred noticeably more emergency response expenditure in 2018-19 than in prior years, largely driven by higher than normal storm activity and severity across its network area. This is shown in Figure 7.

Although similar levels of storm activity may occur in the future, this is not certain. For its Revised Regulatory Proposal, Ergon Energy has reduced its base opex by $12.16 million to reflect a normalised level of emergency response expenditure. This adjustment is explained further in Appendix 3.

Figure 7 Ergon Energy emergency response expenditure ($M, Real $2020)



4.3 Efficiency assessment

Both Energex's and Ergon Energy's base opex is efficient when compared to benchmarks calculated using methods commonly used by the AER – which is consistent with findings made in the AER's Draft Decisions for both networks.[27] As such, no efficiency adjustments are included for either network.

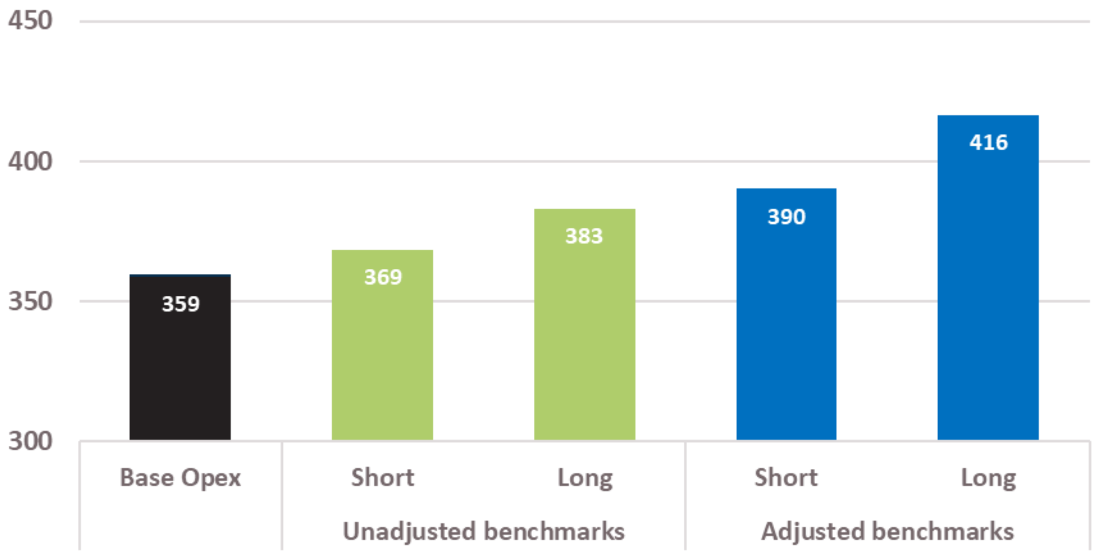
Energex

For Energex, this is not surprising given that actual opex was almost $15 million lower than the estimated opex that the AER assessed in its Draft Decision.

Frontier Economics has applied the benchmarking techniques applied by the AER in that decision, updating for actual opex and the AER's 2019 annual benchmarking report. As shown in Figure 8, Energex's base opex is lower than the efficient opex estimated by the AER's preferred econometric models over the shorter (2012-17) and longer (2006-17) periods – which suggests that Energex's base opex *is* efficient. This is even more so if OEF and model adjustments recommended by Frontier are adopted, as shown on the right-hand side of the figure.

Appendix 2 provides further detail on the economic benchmarking and is supported by Frontier's report (at Attachment *EGX ERG 7.005*).

Figure 8 Energex opex comparison to benchmarks ($M, Real $2020)



Note: RRP opex was adjusted to remove metering and connection services opex and so differs slightly from the numbers shown above. The benchmarks are averages of the estimated efficient opex from the various econometric models and are further explained in Appendix 2.

[27] For instance, in its Draft Decision for Ergon Energy, the AER concluded that:

> *Taking the opex MPFP and econometric benchmarking results together, we have concluded that on balance these results support the finding that Ergon Energy's estimated base year opex is at a level that is consistent with what an efficient benchmarked service provider operating in Ergon Energy's circumstances would require in 2018–19 to deliver its network services, and therefore, is likely to not be materially inefficient. Consequently, we make no efficiency adjustment and use Ergon Energy's current estimate of base year opex for our alternative estimate of base opex.*

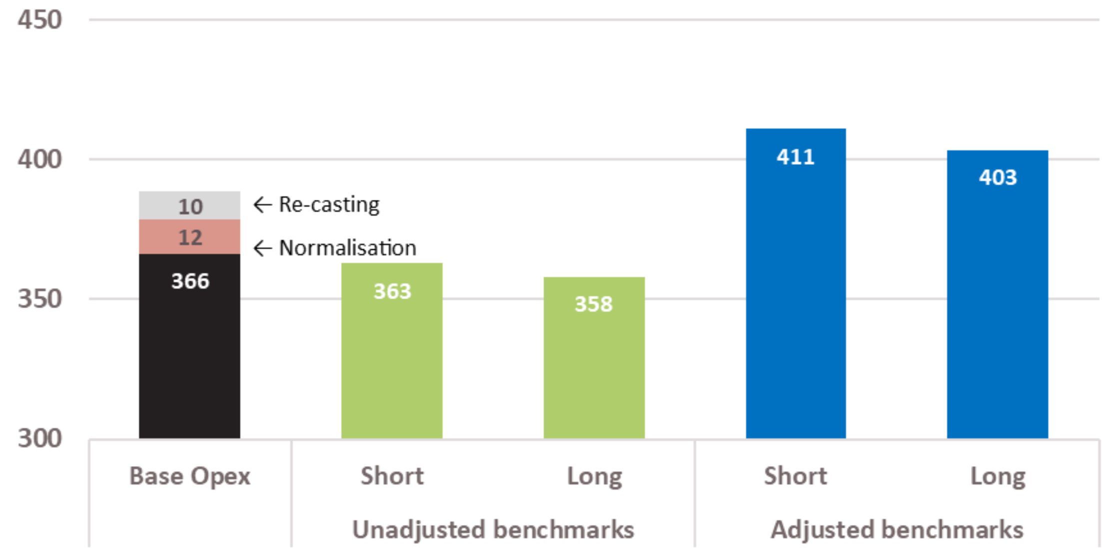
See: Australian Energy Regulator, October 2019, *Draft decision*, *Ergon Energy Distribution Determination 2020 to 2025*, *Attachment 6 Operating expenditure*, p. 6-43.

Ergon Energy

Once the normalisation adjustment is applied, Ergon Energy's adjusted base opex is in line with the efficient opex estimated from the AER's preferred econometric models using data over the shorter (2012-17) and longer (2006-17) periods. This is shown in Figure 9. If the OEF and model adjustments recommended by Frontier are adopted, then Ergon Energy's base opex with or without the normalisation adjustment is significantly lower than the benchmarks, as shown on the right-hand side of the figure.

Appendix 2 provides further detail on the economic benchmarking and is supported by Frontier's report (at Attachment *EGX ERG 7.005*). Frontier also assessed the statistical precision of the estimated efficient opex from the various benchmarking models, finding that they generally have quite large confidence intervals that reinforce the need to take care when using them to assess and determine base year opex – an observation that is particularly relevant to Ergon Energy given that its actual opex is aligned to the unadjusted benchmarks.

Figure 9 Ergon Energy opex comparison to benchmarks ($M, Real $2020)



Note: RRP opex was adjusted to remove metering and connection services opex and to re-cast the historical data to reflect the cost allocation method applying in 2013, reducing base opex by $10 million (referred to as 'Re-casting' in the figure above). As described in section 4.2, Ergon Energy's base opex was also reduced by a further $12 million to normalise emergency response expenditure. This leads to opex benchmarking purposes of $366 million. The benchmarks are averages of the estimated efficient opex from the various econometric models and are further explained in Appendix 2.

4.4 Service classification adjustments

Services are being reclassified for both networks from the start of the 2020-25 period – which means that base opex needs to be adjusted to ensure that it covers standard control services.

In the internal forecasts, both networks retain the service classification adjustments adopted by the AER in its alternative forecasts. These are set out in Table 5 along with an explanation for why they are needed and how the adjustments were calculated.

Table 5: Service classification adjustments ($M, Real $2020)

Name	Energex	Ergon Energy
Explanation	Emergency recoverable work costs incurred when a customer or third party damages the network are currently unregulated. This service will be classified as SCS from the start of the 2020-25 period and so the net costs of providing that service should be included within base opex.	Emergency recoverable work costs incurred when a customer or third party damages the network are currently unregulated. This service will be classified as SCS from the start of the 2020-25 period and so the net costs of providing that service should be included within base opex.
Adjustment ($M, Real $2020)	1.43	0.26
Basis for estimate	Annual cost of repairing third party damage to Energex's network (calculated using 3-year average historical actual costs) *less* the revenue recovered from parties found liable for causing the damage (calculated using 3-year average historical receipts from liable parties).	Annual cost of repairing third party damage to Ergon Energy's network (calculated using 3-year average historical actual costs) *less* the revenue recovered from parties found liable for causing the damage (calculated using 3-year average historical receipts from liable parties).

4.5 Accounting adjustments

Both Energex and Ergon Energy include accounting adjustments to base opex, which are needed to ensure that forecast opex is consistent with how capital expenditure is forecast, the change in ICT charges, and the AER approved cost allocation methodology (or CAM).

Specifically, the three adjustments included are:

- **ICT charges (i.e. SPARQ) changes** – removing the SPARQ asset usage fee as the assets are now being recovered via the regulated asset base
- **Cost treatment alignment** – adjusting how fleet depreciation and shared support costs are accounted for Ergon Energy
- **CAM changes** – introducing the three-factor method for both networks and updates to CAM drivers.

These are set out in Table 6. Appendix 1 provides further detail on the accounting adjustments, including how they were calculated and why they are needed. This is supported by a peer review of our calculations undertaken by PwC (and included as Attachment *EGX ERG 7.008*).

Table 6: Accounting adjustments ($M, Real $2020)

Name	Energex	Ergon Energy
ICT charges changes	(9.44)	(12.93)
Cost treatment alignment	-	22.82
Cost allocation changes	12.43	(4.50)
Total	**2.99**	**5.39**

4.6 Final year adjustments

As per the Draft Decisions for both networks, both networks have retained the final year adjustment calculations contained within the AER's opex model, which are used to convert revealed opex (i.e. for 2018-19 in our case) to the final year of the current regulatory period (i.e. 2019-20). The updated values are set out in Table 7. The calculations are further explained in the AER's Draft Decisions.

Table 7: Final year adjustments ($M, Real $2020)

Name	Energex	Ergon Energy
Estimated change between the base year and the final year	2.36	7.32
Remove estimated final year opex for categories forecast specifically	(0.13)	(0.07)
Total	**2.24**	**7.24**

5. Trend

Once base opex is determined (see chapter 4), the BST method trends it forward over the relevant regulatory period.

Energex and Ergon Energy have retained the calculations, inputs and assumptions used by the AER in its alternative forecasts published with the Draft Decisions, with two exceptions:

- **Real input cost escalation** – we do not agree with the AER's proposal to rely only a single independent forecaster (DAE), and have instead averaged forecasts from that forecaster with another (BIS Oxford)
- **Output growth –** we have updated the demand-related growth factors to align with other updates made through the Revised Regulatory Proposals for both networks.

These two items are discussed below along with why we have adopted the AER's industry-wide productivity factor.

Over the 2020-25 period, the trend adds $60.22 million and $32.30 million to forecast opex for Energex and Ergon Energy, respectively, as shown in Table 8.

Table 8: Impact of trend ($M, Real $2020)

	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Energex						
Output change	4.29	8.36	12.25	16.04	20.25	**61.19**
Price change	1.50	3.41	5.42	7.51	9.08	**26.92**
Productivity change	(1.84)	(3.66)	(5.48)	(7.29)	(9.09)	**(27.37)**
Balancing	(0.01)	(0.04)	(0.09)	(0.15)	(0.24)	**(0.52)**
Total trend	**3.95**	**8.06**	**12.11**	**16.12**	**19.99**	**60.22**
Ergon Energy						
Output change	1.73	4.17	6.51	9.03	11.87	**33.30**
Price change	1.57	3.57	5.69	7.88	9.52	**28.22**
Productivity change	(1.93)	(3.84)	(5.75)	(7.64)	(9.53)	**(28.69)**
Balancing	(0.01)	(0.04)	(0.09)	(0.15)	(0.24)	**(0.53)**
Total trend	**1.37**	**3.86**	**6.36**	**9.11**	**11.61**	**32.30**

5.1 Real input cost escalation

The January 2019 Regulatory Proposals for both networks used the average of forecasts prepared by DAE) and BIS Oxford for real labour cost escalators, and assumed that real material cost escalation was zero. The Revised Regulatory Proposals retain this approach but used updated forecasts for real labour costs from each independent forecaster.

AER's proposed approach

In its alternative forecasts, the AER used only real labour cost forecasts provided by DAE, citing concerns with the accuracy of BIS Oxford's forecasts.

The AER's proposed change in approach is a notable departure from past practice and good regulatory practice. In all recent decisions the AER has accepted using an average of DAE and BIS Oxford. Departing from this practice should really be subject to an industry-wide consultation; similar to what the AER has undertaken recently for productivity and tax. This would give stakeholders opportunity to comment, especially given the consequences and the concerns with the AER's analysis that underpins its change (which we discuss below).

Forecasting is inherently uncertain. Relying on a single data provider creates significant risks and can lead to higher forecasting error than relying on more than one forecaster.

A similar logic has led the AER to use averages in other parts of its decision making. Perhaps the most obvious is when estimating the prevailing return on debt for a given averaging period; where the AER – based on either the 2013 rate of return guideline or the 2018 binding rate of return instrument – calculates that value by averaging two or more estimates provided by independent data providers (i.e. the Reserve Bank of Australia, Bloomberg and Thomson Reuters).

There is a good basis for doing so. Prior analysis by the AER has shown that data providers can and have provided inaccurate data, and in some cases for extended periods of time. Averaging data sources helps reduce the risk of such an error affecting a regulatory outcome.

AER's analysis

To support its proposed change the AER relied on recent analysis it had undertaken testing how various forecasts provided by each of DAE and BIS Oxford compared to actual labour escalation (as estimated by the Australian Bureau of Statistics (ABS)). The AER found that BIS Oxford's forecasts were less accurate than DAE's.

After reviewing the AER's analysis, BIS Oxford has responded to these findings in the report provided at Attachment *EGX ERG 7.003*, concluding that:[28]

> *The key conclusion from our analysis is that departing from the AER's current approach of averaging the projections produced by DAE and BISOE for growth in the all-industries and the EGWWS real WPI, by just using the DAE projections for these series, is statistically likely to result in a worse outcome (in terms of forecast accuracy) than continuing to use the current approach of averaging the two series. Moreover, for the national all-industries WPI in particular, we and the AER both find that the forecast performance of both firms has been broadly similar historically; given this, the AER's initial basis for departing from the averaging approach, that DAE's historical performance is better, is not the case.*
>
> *The key implication of the potential decision to just use DAE forecasts is that this risks the AER consistently producing less accurate projections for the efficient labour costs of Energy*

[28] BIS Oxford, December 2019, *Review of AER forecast comparison*, *Report produced for Energy Queensland*, p. 3.

Queensland. This could result in the firm being unable to recover the efficient costs associated with the expenditure objectives in the National Electricity Rules.

There are at least five broad challenges with this analysis:

- **First**, the AER has not actually tested whether its new proposed approach (DAE only) is more accurate than the past approach (averages of DAE and BIS Oxford) for relevant regulatory determinations. Without testing that past approach it is difficult to see exactly how the AER's analysis supports its proposed change. It is true that in almost all cases when comparing two forecasters one will be more accurate than another on certain measures; it would have been odd if DAE and BIS Oxford had the same accuracy score. But to rely on such an outcome to support a proposed change to just one forecaster without testing how the average performs, is premature.
- **Second**, the AER is testing forecasts of *actual* labour costs against *estimates* of those costs, and so they cannot actually say which forecast is more accurate. The key is that the ABS uses surveys and other methods to estimate what the labour costs are; but as estimates they are also likely to be wrong and will certainly have statistical uncertainty surrounding them (as all surveys do). Asking 5,000 or so businesses about their labour costs can only ever be indicative of what actual labour costs are across the country, state or territory. As such, the AER's test results can only show how accurate the forecasts are at predicting the ABS estimates, not actual labour costs.
- **Third,** the AER has used a relatively small sample period, especially when compared to the length of the forecasting periods commonly used (i.e. 5 or 6 years). Small sample sizes tend to lead to large statistical uncertainty around the results, which may well be the case with the AER's analysis.
- **Fourth**, as is common in finance-related warnings, past performance is not a reliable predictor of future outcomes. This same warning applies here. The AER has tested past performance over a relatively short period. It is imprecise to extrapolate that finding to say that DAE will be more accurate than the average of DAE and BIS Oxford over the next 5 or 6 years.
- **Fifth**, the AER's approach does not account for changes in forecasting approaches used by either DAE or BIS Oxford over time. It may be that at various points in time DAE or BIS Oxford used approaches that were more accurate than the other. However, as with all fields, techniques, skills, tools, and personnel change can dramatically improve or worsen a forecaster's relative accuracy. Testing *old* forecasting approaches as the AER has effectively done says little about how accurate the *current* forecasting approaches used by DAE or BIS Oxford are, including because they will be affected differently by market dynamics and other external factors that have changed over time.

In summary, the AER's analysis is insufficient to prove that BIS Oxford's current forecasts are less accurate than DAE's or an average of the two. And so, in the internal forecasts, Energex and Ergon Energy have stuck with the AER's past practice and their January 2019 Regulatory Proposals by relying on the average of forecasts provided by DAE and BIS Oxford.

Internal Forecasts

Table 9 sets out the real labour cost forecasts for the 2020-25 period used in our internal forecasts. The final column of the table shows the cumulative impact of the labour cost escalators over the period.

Table 9: Real labour cost changes

	2020-21	2021-22	2022-23	2023-24	2024-25	Cumulative
DAE	0.47%	0.63%	0.52%	0.58%	0.50%	**2.73%**
BIS Oxford	0.90%	1.10%	1.30%	1.30%	0.90%	**5.62%**
Average	**0.68%**	**0.86%**	**0.91%**	**0.94%**	**0.70%**	**4.17%**

Note: The DAE forecasts are taken from the AER's Draft Decisions. The BIS Oxford forecasts are sourced from an updated independent expert report, contained at Attachment *EGX ERG 7.004*.

5.2 Output growth

Energex and Ergon Energy have retained the same approach to forecast output growth as included in the January 2019 Regulatory Proposals and per the AER's alternative forecasts. We also retained the growth factor weights used in the alternative forecasts. The only changes were to was to update the demand-related growth factors to reflect the latest forecasts being used elsewhere in the Revised Regulatory Proposals (see Chapter 5 of the Revised Regulatory Proposal).

Table 10 sets out the updated growth factor forecasts for both networks.

Table 10: Growth factor forecasts

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Energex						
Customer numbers (#)	1,505,249	1,525,955	1,546,472	1,567,625	1,588,875	1,610,463
Circuit length (km)	54,704	55,137	55,632	56,086	56,551	57,049
Ratcheted maximum demand (MW)	5,055	5,110	5,148	5,177	5,197	5,235
Energy throughout (GWh)	21,426	21,445	21,517	21,484	21,515	21,587

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Ergon Energy						
Customer numbers (#)	738,444	744,049	751,961	759,601	767,234	774,870
Circuit length (km)	152,522	152,811	153,096	153,409	153,696	153,984
Ratcheted maximum demand (MW)	2,545	2,545	2,545	2,545	2,549	2,564
Energy throughout (GWh)	13,521	13,454	13,434	13,389	13,406	13,330

Note: To convert the growth forecasts into a output growth rate of change we used the weights adopted by the AER in its alternative forecasts.

5.3 Productivity

Energex and Ergon Energy are proposing to adopt the AER's industry-wide productivity factor of 0.5% per year for their Revised Regulatory Proposals. This is a change from the January 2019 Regulatory Proposals – which included somewhat ambitious productivity factors of 1.72% and 2.58% per year for Energex and Ergon Energy, respectively.

As explained in section 3.2, this change is needed to ensure that the networks can continue to deliver the operating expenditure outcomes that customers seek without undermining our affordability commitment. Such a change is also consistent with feedback from stakeholders that questioned EQ's ability to realise such improvements without undermining customer outcomes (see section 2.3)., which is a valid concern.

In its Draft Decisions, the AER adopted a 0.5% productivity factor after completing an industry-wide consultation that finished in March 2019 – two months after we submitted our Regulatory Proposals (with their ambitious productivity factors). The AER explained that the 0.5%:[29]

> *reflects the best estimate of the opex productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward, rather than any efficiency catch-up by individual distributors.*

After careful consideration and comfort that the affordability objective will be achieved with the Revised Regulatory Proposals, Energex and Ergon Energy have both adopted the 0.5% used in the AER's alternative forecasts.

[29] AER, 8 March 2019, *Forecasting productivity growth for electricity distributors, Final decision paper*, p9.

6. Step Changes

Our revised regulatory proposals include more detailed businesses cases for our capital program, including for our investment in facilitating non-network items that can lower our operating costs. Our business cases for ICT[30] and property all quantify the benefits we expect these targeted investments to deliver for our operating and overhead costs and the year in which they will be realised.

Some of the savings are general improvements in labour productivity whereas others lead to specific avoided or lessened costs. Some are realised at the EQL level, and have been allocated our to each network using our AER-approved CAM for the next period. Others accrue to each network and have been assessed as a capex or opex saving using our capitalisation policy and accounted for accordingly.

Below we set out the nature and value of opex negative step change savings arising from each form of investment. Importantly, we note that our ability to realise these step changes is dependent on the corresponding investment being approved at the value we have forecast in our business cases.

6.1 Property savings

Our property investment and renewal program has been designed to deliver real operational savings. These tangible savings are quantified in each relevant business case, and include savings associated with avoided lease costs, avoided rates and land taxes, reduced electricity and water costs, reduced maintenance costs etc, net of the costs of returning leased sites to their initial condition (i.e. make-good costs).

In relevant business cases (see below) the delta between the Base Case and the Preferred Option in any financial year is the opex saving resulting from the investment.

In several investments, opex increases in the first years of the investment then decreases. For example, if moving to a new site, there's a period of time while EQ owns two sites, and there are therefore two sets of council rates, land tax etc. The net saving (or increase) in opex in each financial year is shown in each business case, along with the cumulative total saving for the 2020-25 period.

Importantly, we note that the financial year savings aren't the same as a step change. To be consistent with the base, step and trend approach, the step change must be calculated as the difference in saving between two successive financial years. For example, if the saving in the 2021-22 financial year is $600,000 and the saving in 2022-23 financial year is $700,000 the step change between those two years is $100,000 (i.e. $700,000-$600,000).

These tangible savings are in addition to what our business cases classify as 'benefits'. These more general or 'soft' savings relate to expected (and thus quantified) productivity improvements. The property business cases identify and estimate these as relevant including for items such as:

- Productivity benefits
- Reduced staff movements
- Staff productivity improvement
- Reduced travel costs
- Training delivery efficiency
- Theft impact reduction

30 Note that these were already provided to the AER in response to its information requests in 2019.

- Reduction in manned patrols
- Improvement in staff productivity through reduced business outages
- Transport logistics efficiency
- Remove double handling - storage onsite/offsite
- Productivity efficiency of having two builds in parallel.

Table 11 sets out the annual value of these step changes for each network, and

Table 12 references the business cases underpinning these and which networks they relate to.

Table 11: Property savings step change ($M, Real $2020)

Name	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Energex	-	-	0.17	0.90	0.88	**1.95**
Ergon Energy	(0.03)	(0.06)	0.11	0.92	1.00	**1.94**
Total	**(0.03)**	**(0.06)**	**0.28**	**1.82**	**1.89**	**3.89**

Table 12: Supporting business cases

Name	Ref	Energex	Ergon Energy
PR01 Maryborough Consolidation	*ERG 6.038 Business Case Maryborough Redevelopment DEC19 PUBLIC*		Yes
PR02 Brisbane Office Accommodation	*EGX ERG 6.009 Business Case Brisbane Office Accommodation DEC19 PUBLIC*	Yes	Yes
PR03 Rocklea Training	*EGX 6.024 Business Case Rocklea Training Facility DEC19 PUBLIC*	Yes	
PR04 Property Security	*EGX ERG 6.010 Business Case Non-Network Security DEC19 PUBLIC*		Yes
PR05 Townsville Training	*ERG 6.037 Business Case Townsville Training Facility DEC19 PUBLIC*		Yes
PR06 Rockhampton (OTHF)	*EGX ERG 6.013 Business Case Rockhampton OTFH*	Yes	Yes

6.2 ICT savings

Our ICT investment program will support our digital transformation and drive broad-ranging productivity enhancements across our operations. Consistent with the AER's Draft Decision feedback, we have removed these from our opex forecasts as a negative step change.

Table 13 sets out the annual value of these step changes for each network.

Table 13: ICT savings step change ($M, Real $2020)

Name	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Energex	-	0.05	1.02	2.58	3.58	**7.23**
Ergon Energy	-	0.03	0.92	2.39	3.23	**6.56**
Total	**-**	**0.08**	**1.94**	**4.97**	**6.81**	**13.79**

Table 14 references the business cases underpinning these, described the types of benefits quantified for each of these, and shows which networks they relate to. These businesses cases have previously been provided to the AER.

Table 14: Supporting business cases and expected benefits

Business case	Benefits
ID01 GIS Consolidation & Replacement	Network data management productivity improvement through: • simplified workflows • focus on accurate data capture at source, with reduced need for rework • reduced network model duplication and synchronisation. Network asset investment planning and decision-making improvement through: • more accurate network data with spatial analysis capability • spatial overlays of environmental, climate, demographic, social and other data sets • improved interconnection of network data with operational performance data (DMS) and fixed asset data (ERP EAM) Network asset lifecycle management improvement through: • improved GIS spatial network model management solution capability • improved ability to overlay non-network information for analysis efficiency • state-wide aggregation of asset management workload, continuous improvement is asset management processes with full rollout of ISO55000 practices and with state-wide insights and network intelligence.
ID02 Network Operation Systems Consolidation & Replacement	ICT Support Productivity through reduced ICT custom application support associated with maintenance of highly aged custom built applications requiring specialist skills. Network Operations Performance improvement through consolidation of Energex and Ergon Energy network control and operational work practices, reducing duplication and enabling improved productivity.
ID03 Field Force Systems Consolidation & Replacement	Program delivery productivity through: • Transition to a single work program delivery model for planned and unplanned work, supporting further program of work optimisation. • Provision of contemporary FFA capability enables improvement through higher levels of work bundling, flexible resource and work allocation methods. • Storm and Significant Event Management Improvement • Improvement in management of storm and significant events through incorporation of analytics to assist in work scheduling and dispatch. Compliance Productivity through: • Agility and synergy in responding to changes in market rules transaction specifications.
ID04 Customer Market Systems Consolidation & Replacement	Market Operations Productivity through better resource utilisation through alignment of processes and allocation of resources across the shared Energex and Ergon Energy Market Operations function. Compliance Productivity through agility and synergy in responding to changes in market rules transaction specifications.

Business case	Benefits
ID05 Design Tools Consolidation & Replacement	Design productivity through: • Process improvement through reduced manual actions. • Aggregation of lines design and communications design workload for optimal workforce productivity. • Design delivery improvement through consistency of calculations and common lines design building blocks. Communications network management effectiveness through: • Ad-hoc, labour intensive planning is minimised through a communications design toolset that has appropriate planning capabilities. • Productivity improvement through communications tool integration with the Unified GIS.
ID06 Distribution Forecasting Consolidation & Replacement	Distribution forecasting productivity through: • Distribution forecasting process improvement through reduced manual actions. • Aggregation of distribution forecasting workload for optimal workforce productivity. • Distribution forecasting delivery improvement through consistency of scenario modelling and common calculations and assumptions. Capital works program optimisation through: • Enhanced trend and scenario modelling capabilities providing more granular understanding of future demand, driving improved network capital investment decision-making. • Network investment plans can be tailored to the local requirements of particular network segments (small area modelling capabilities). • Opportunity to reduce or defer capital investment through better analysis of customer energy usage and targeting of demand management programs. • Opportunity to deploy non-network alternative solutions, through a more granular understanding of the low voltage network.
ID07 Contact Centre Technology (CCT) Consolidation & Replacement	Market operations productivity through: • Better resource utilisation through alignment of processes and allocation of resources across the Customer Operations and Market group. • Reduced level of agent-based customer interactions – as a percentage of call volume – as automated solution delivers the required customer experience. Compliance productivity through agility and synergy in responding to changes in market rules transaction specifications.
ID08 Information Repositories Consolidation & Replacement	Reporting and analysis through: • Alignment and simplification of data collation and analysis across Energex and Ergon Energy. • Simplification of RIN reporting and internal review / verification. Asset Management optimisation of asset maintenance through effective condition assessment and defect / failure mode analysis.
ID09 Service Interaction Portals Consolidation & Replacement	Customer operations productivity through: • Provision and use of self-serve capability enables productivity improvement through first-response automation. Compliance Productivity through agility and synergy in responding to changes in market rules transaction specifications.
ID10 Meter Data Management (MDM) Consolidation & Replacement	Market operations productivity through: • Reduced manual intervention in meter data validation, substitution and estimation activities • Reduced number of queries from the market in relation to published meter data. Distribution metering productivity through synergy arising from consolidation of meter data and meter management systems (i.e. Toht and MARS respectively). Efficiency will be achieved through reduced effort in data corrections and a single source of truth for metering data.

Business case	Benefits
ID11 Asset Inspections Consolidation & Replacement	Asset inspections and monitoring productivity through: • Aggregation of asset inspections and condition monitoring workload for optimal workforce productivity • Labour intensive usage of the CBRM and JAMIT tools is reduced through integration with the Unified ERP EAM. Asset management improvement through: • Improved judgements on asset replacements or repair through additional asset condition information capture and improved analysis, resulting in reduced asset failures • Improved identification of trends related to network defects and maintenance issues, through improved asset condition information and analysis, resulting in a reduced corrective maintenance.
ID12 Document Management Consolidation & Replacement	Organisational productivity through: • Improved shared services productivity through streamlined best practice processes in document and records management. • Reduced search time to find and retrieve documents.
ID13 ICT Management Tools Replacement	ICT Operations Productivity, involving improved operational productivity resulting from a consolidated and contemporary ICT management toolset. Benefit is derived from improvements in: • ICT task management • Fault and defect diagnostics • Root cause analyses and enablement of ICT continuous improvement practices • ICT system monitoring • Reduction in effort associated with maintaining duplicate ICT asset configuration management • ICT architecture accessibility, flexibility and design efficiency
ID14 Customer Management Systems Consolidation & Replacement	Customer operations productivity through: • Reduced cost to serve due to automation provided by push type communications with customers • Agility and synergy in responding to changes in market processes • Major Customer Management Productivity • Improved functionality and ease of use for staff, customers and partners will improve major customer experience, support cost to serve reductions and more efficient interaction handling
ID15 Network Planning Tools Consolidation & Replacement	Network planning productivity through: • Labour intensive set-up and validation of the DINIS and PSS-SINCAL models is reduced through integration of planning tools with the Unified GIS. • Productivity improvement through improved automation. • Reduction in costs from third party providers conducting network studies on behalf of Energex and Ergon Energy. Capital works program optimisation through: • Improved network data and analysis capability, network investment plans can be tailored and optimised • Improved accuracy in network investigations at the low voltage and small area network level, resulting in Energex and Ergon Energy’s ability to integrate new technologies, such as Microgrids.
ID16 Process Management Systems Consolidation & Replacement	Operational productivity through: • Improved operational productivity resulting from easy access to common best practice processes • Ability to model processes to assess change impact and improved monitoring and automation. Process Management Productivity through reduced effort associated with content administration through the consolidation of current independent process management systems.

Business case	Benefits
ID18 Internet Websites Consolidation & Replacement	Customer Operations Productivity through increased ability to address customer enquiries and ongoing information needs via the web channel, thereby reducing the level of agent-based customer interactions. Content Management Productivity through reduction of effort associated with maintaining and supporting separate website solutions including content administration and approvals, search engine optimisation, accessibility compliance and other activities.

Appendix 1. Accounting Adjustments

1. Summary

Amendments changes to the AER-approved cost allocation methodologies (CAMs) to have effect from 1 July 2020 and changes to the way that ICT services are to be acquired have led to five accounting adjustments to base opex for both Energex and Ergon Energy.[31]

Adjustments

The adjustments are grouped into three categories, as follows:

- **ICT charges changes –** where financing and depreciation charges for ICT assets currently levied by SPARQ as an asset usage fee and passed through as an overhead, will now be recovered via the return on and of ICT assets rolled into the Energex and Ergon Energy RABs from 1 July 2020
- **Cost treatment changes** – where, through the adoption of consistent application of accounting approaches for Ergon Energy, fleet depreciation costs should be removed from base opex and some previously capitalised corporate overheads should be expensed from 1 July 2020 onwards
- **Cost allocation changes –** where, due to changes in the CAMs for both Energex and Ergon, some costs are moved from Ergon Energy to Energex as a result of the distribution 3-factor method, and other costs transferred to standard control services opex by adopting a consistent definition of cost pool allocation drivers.

In its Draft Decisions, the AER did not include the accounting adjustments in its alternative opex forecasts for Energex and Ergon Energy. The AER stated that Energex and Ergon Energy failed to explain and justify these.

While the Draft Decisions did not apply the accounting adjustments because it could not reconcile them, the AER helpfully provided a dedicated appendix (Attachment 6 appendix B) to set out the information the AER require in our Revised Proposals should Energex and Ergon Energy wish to include this adjustment to the base year operating expenditure. Although we have adopted the opex allowances in the AER's Draft Decisions, we have included these adjustments in our internal forecasts.

Table 15 identifies the changes for Energex and Ergon Energy, with the combined impact set out in the right-hand column. Once the offsetting capitalised overhead adjustment is factored in, the net impact of the adjustments is positive $2.99 million per year for Energex and negative $38.66 million for Ergon Energy per year.

[31] On 14 December 2018, the AER approved a revised CAM to apply to both networks from 1 July 2020. The revised CAM incorporates changes brought about by the creation of Energy Queensland Limited (EQL) that will affect how costs are allocated to distribution services, adjusting those that would apply under the current CAMs applying separately to the two networks that currently govern the data reported in response to RINs.

Table 15: Accounting adjustments ($M, Real $2020)

Name	Energex	Ergon Energy	Combined
ICT charges changes			
SPARQ asset usage fee	(9.44)	(12.93)	**(22.37)**
Sub-total	*(9.44)*	*(12.93)*	***(22.37)***
Cost treatment alignment			
Fleet depreciation	-	(8.36)	**(8.36)**
Change in Ergon Energy's capitalisation practices for shared (support) costs	-	44.06	**44.06**
Ergon Energy overhead recoveries true-up (see Appendix 4)	-	(12.88)	**(12.88)**
Sub-total	-	*22.82*	***22.82***
Cost allocation			
Distribution three-factor method	5.72	(5.72)	**-**
Other CAM cost driver changes	6.71	1.22	**7.93**
Sub-total	*12.43*	*(4.50)*	***7.93***
Total opex (reflected in base year opex)	**2.99**	**5.39**	**8.38**

Note: the $44.06 million increase in Ergon Energy's base opex due to the capitalisation change is fully offset by a $44.06 million reduction in capitalised overheads.

Purpose of this appendix

This appendix further explains the accounting adjustments, including by providing further explanation and information about each of them. The appendix is supported by several attachments that provided the supporting data and calculations, and a PricewaterhouseCoopers (PwC) review of the model and supporting documents (see the spreadsheet labelled *CAM Reconciliation – Working V4*), see Attachments *EGX ERG 7.007* and *EGX ERG 7.008*.

The adjustments *have* changed since our January 2019 Proposals because we have replaced estimated data (based on the 2018/19 budget) with actual data (based on our audited 2018/19 RIN responses for both networks).

First, we outline why the CAMs were changed, which provides important background to the adjustments described further below. Then we step through each of the adjustments.

2. Why the CAMs were changed

Both the current Energex and Ergon Energy CAMs comply with the AER's cost allocation guideline.[32] However, through the merger of the networks it became clear that there were differences between the approved CAMs that made it hard to merge the accounting practices needed to apply those CAMs.

This observation – along with changes to the corporate and organisation structure – led to the network businesses proposing and the AER subsequently approving a common CAM to apply to both businesses from 1 July 2020 onwards.

Differences between CAMs

Energex and Ergon Energy currently have similar categories of direct costs. A key difference between their current CAMs is that Ergon Energy directly attributes all fleet costs whereas Energex allocates fleet on-costs based on direct labour.

Ergon Energy and Energex also apply a different approach to determining the overhead cost pool:

- Energex calculates a regulatory cost pool, by removing its on-costs (fleet and material), unregulated support costs (including those calculated using the three-factor approach) and other operating costs from its shared (indirect) costs, while
- Ergon Energy applies several different allocators to its various cost categories in order to calculate shared cost percentage rates for opex and capex respectively.

Once they have determined the overhead cost pool, both Energex and Ergon Energy allocate the costs in proportion to their direct costs.

Key differences between the two CAMs are summarised in Table 16.

Table 16: Comparison of current CAMs

Key differences	Energex	Ergon Energy
Allocation of shared (support) costs to operating and capital expenditure	Total shared costs were first allocated between regulated and unregulated services as a proportion of direct expenditure (both capital and operating). This meant that the capital and operating portion of shared costs was determined based on direct capital and operating expenditure. The overhead rate applying to direct expenditure was: *[Total regulated OH]/[Total direct expenditure]*	Shared costs were first split between operating and capital expenditure pools before being allocated across regulated and unregulated services based on direct expenditure (either capital or operating)
Excluded costs from the regulated overheads pool that was subject to capitalisation	Certain regulated costs were excluded from the regulated overhead pool used to calculate regulated overhead rate; in particular, audit, legal, finance, insurance costs. This meant that those corporate costs were not capitalised	No costs were excluded from the shared costs and so all costs were capable of being capitalised
Treatment of fleet depreciation	Excluded from the general overhead pool, which means that it was not allocated	Included within the general overhead pool, part of which was capitalised through the overhead allocation process

[32] See: Australian Energy Regulator, 26 June 2008, *Electricity distribution network service providers*, *Cost allocation guidelines*.

Key differences	Energex	Ergon Energy
Costs allocated to unregulated services	Costs were allocated to unregulated services based on equal weighting of asset, headcount and revenue percentages	Costs were allocated to unregulated services based on number of transactions, headcount or time spent as appropriate
Non-system capital expenditure allocation	Based on the proportion of labour incurred in delivering services within each classification.	Based on forecast usage for each asset class
Fleet on-cost	Applies fleet on-cost	Applies direct cost using unit rate for specific vehicle class

Common CAM

Given the above highlighted differences, Energy Queensland develop a new 'common' CAM to apply to both networks that was designed to be:

- Consistent with the AER's cost allocation guideline (and Chapter 6 of the National Electricity Rules), and
- Minimise disruption to existing cost allocation and related processes.

Key design principles included:

- Considering the economic substance over legal form – that is, how various activities have been or will be organised within the Energy Queensland group
- Clarifying the role for each legal entity is the first step to understand how activities are organised within the group
- Costs need to attribute to each activity or service where benefits are being consumed – the common CAM should focus on costs related to shared services, noting that shared services costs may allocate across lines of business in different ways (as benefits may differ)
- Direct charge costs whenever possible – that is, costs that can be specifically attributed to a cost object
- When a line of business provides a service to another line of business, the service provider is to charge the service at cost (i.e. to allocate cost to service recipient at fully burdened cost, costs includes items such as salaries, contractors, travel and overhead) – there should be no additional mark-ups for a profit component
- Allocation of indirect costs or general and administrative costs should be based on appropriate cost driver – the allocation process should be fair, identifiable, simple and consistent, with cost drivers either being fixed parameters (e.g. number of FTEs) or time estimates (e.g. allocated based on time spent on a task or activity)
- There should be no cross-subsidisation between regulated and non-regulated businesses

The new CAM that resulted is summarised in Table 17.

Table 17: Summary of the new CAM

Component	Approach adopted	Rationale
Direct costs	The direct attribution of costs will apply in the same manner for Energex and Ergon Energy for operating and capital expenditure. This covers labour (and labour related costs), inventory and materials, third party contractor, and various other costs There is no change in what is currently applied by the businesses, except that: • **Material on-costs.** These will be incorporated in the unit rate for Energex rather than separately allocated. Ergon Energy's	The approach is simple to administer and aligns approaches across both networks. Only costs that are directly attributable are directly attributed

Component	Approach adopted	Rationale
	direct cost already includes on-cost. The unit rate cost applied for forecasting for Energex will correspondingly increase. There will be no change for Energex's reported direct material costs as direct costs reported in the CA RIN already include on-costs. • **Fleet costs.** These will be allocated between lines of business and services as part of non-network rather than being included as part of direct costs (as Ergon Energy does) or included as an additional on-cost to direct labour (as Energex does). Ergon Energy's forecast unit costs for direct costs will decrease. Direct costs reported in the CA RIN by both businesses will therefore decrease.	
Shared costs	Shared costs are allocated between the Energy Queensland lines of business (distribution, retail and Yurika), and between distribution services as follows: • **Overall.** Shared costs are classified as either network or corporate overheads and allocated in a two-step process with costs *first* allocated to lines of business and *then* to services (standard control services, alternative control services, non-regulated) • **Lines of business.** Shared costs are allocated to lines of business using two stages: ○ Network overheads are allocated between Energex and Ergon Energy using a *distribution* 3-factor method[33] – this is a move away from the causal allocation approached reflected in Ergon Energy's CAM and towards the 3 factor formula in Energex's CAM ○ Corporate overheads are first allocated across lines of business using a *corporate* 3-factor method (with the distribution networks being a single unit), and then between Energex and Ergon Energy using the *distribution* 3-factor method[34] • **Services.** Shared costs allocated to Energex and Ergon Energy are then allocated to their respective services based on direct spend for support costs (overheads) and direct labour for non-system costs (non-network).	The corporate and distribution 3-factor methods are relatively simple to apply (and backcast), including because the inputs to it are already currently produced as part of business-as-usual activity and are subject to annual reporting and audit. Using direct costs to allocate shared costs to services is also easy to apply and consistent with the current CAMs.

3. SPARQ asset usage fee

Explanation

Prior to December 2017 Energex and Ergon Energy each had a 50% interest in a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ). Each network paid SPARQ in accordance with service level agreements.

A corporate restructure occurred effective 1 December 2017 whereby EQL took up 100% ownership of SPARQ, with the entity being dissolved and ICT activities being brought in-house. For regulatory purposes, the ICT asset costs are now intended to be recovered via the RABs for each network (rather than via opex). Any undepreciated legacy ICT assets will be added to the RABs from the start of the

33 Network overheads cover common asset management and business specific field services shared across Energex and Ergon Energy. These costs are allocated only across those two networks using the distribution 3-factor method based on an equal weighting of direct spend, customer numbers and asset value.

34 Corporate overheads relate to expenditure incurred by corporate units to provide management and support services across *all* Energy Queensland lines of business, and include finance, legal and secretariat, strategy, regulation and stakeholder engagement, and human services. These costs are allocated across all lines of business – with Energex and Ergon Energy being treated as a single 'distribution' line of business – using the corporate 3-factor method based on an equal weighting of asset value, revenue and labour.

2020-25 period.[35] To ensure that those costs are not recovered twice, the depreciation and financing charges on those assets that SPARQ previously charged the networks are being removed from base opex – as a negative base year adjustment.

The AER described this – in the case of Ergon Energy – as follows: [36]

> *The legacy ICT assets were previously owned by a third party entity SPARQ (which was part of Energy Queensland) but used to provide ICT services for Energex and Ergon Energy in the 2015–20 regulatory control period. With the merger of the two entities to Energy Queensland in 2017, these functions will be performed by Ergon Energy going forward. Customers paid asset usage charges as part of the opex allowance during the 2015–20 regulatory control period for these services. This opex charge will be removed going forward and instead Ergon Energy will recover the associated costs through the return on and of capital for these assets from 1 July 2020.*

The asset usage charges expensed equated to $9.44 million and $12.93 million for Energex and Ergon Energy respectively in the 2018-19 financial year.[37]

The AER accepted the need for these adjustments in its Draft Decisions but requested further evidence to demonstrate the quantum of the adjustment in terms of its net impact on total (direct and indirect) opex.[38]

Calculation

At the time of preparing the January 2019 Proposals for both Energex and Ergon Energy, estimates of the asset usage charges for 2018-19 were used as actual data was not available. For the Revised Regulatory Proposals we have used actual data, which means that we are not relying on 2018-19 budgeted information.

In 2018-19 the total SPARQ asset usage fee was $43.47 million (in $nominal), the amounts allocated to Energex and Ergon Energy SCS opex were $9.21 million and $12.61 million (both in $nominal) using the allocators adopted to populate the 2018-19 RIN responses. These values equate to $9.44 million and $12.93 million (in Real $2020), once adjusted for inflation.

The underlying calculation spreadsheets and data are provided in the spreadsheet labelled *CAM Reconciliation - Working V4* available at Attachment *EGX ERG 7.007* (see cells E40 and E21 of the '7. Results' sheet).[39]

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35 See, for instance, AER, October 2019, *Attachment 2: Regulatory asset base | Draft decision – Ergon Energy 2020-25*, pp. 2-17 to 2-18. The AER's Draft Decision was to only incorporate legacy ICT assets into the RAB to the extent that they had not fully depreciated.

36 AER, October 2019, *Attachment 2: Regulatory asset base | Draft decision – Ergon Energy 2020-25*, p. 2-17.

37 The unadjusted $nominal values are $9.21 million and $12.61 million respectively.

38 See, for instance, AER, October 2019, *Attachment 6: Operating Expenditure | Draft decision – Ergon Energy 2020-25*, p. 6-86. Although the AER refers to a net impact on total direct and indirect opex, there is no offsetting opex impact from the SPARQ change. Rather, the SPARQ assets are now being allocated across the Energex and Ergon Energy RABs and so the only opex adjustment is to remove the depreciation and financing charges that were previously charged by SPARQ.

39 Energy Queensland develop a '*CAM Reconciliation model*' to both identify the SPARQ asset usage fee and the impact of applying the new CAM. This model was reviewed and assessed for consistency with the application of the new CAM, affective from 1 July 2020, by PwC.

Validation

Although the specific charges were not audited, the financial data included in our RIN responses that included those charges *was* audited. We also engaged PwC to review the accuracy of the modelling used to identify the share of the SPARQ asset used fee to each of Energex and Ergon Energy. PwC's report is available at Attachment *EGX ERG 7.008*.

4. Ergon Energy fleet depreciation

Explanation

Consistent treatment across both Energy and Ergon Energy means that depreciation on fleet assets will no longer be allocated to the network from 1 July 2020 onwards. The adjustment – of negative $8.36 million[40] – removes that depreciation from Ergon Energy's 2018-19 SCS opex.

Specifically,

- Section 9.2 of Ergon Energy's *current* CAM designates fleet charges as directly attributed costs and includes depreciation[41] – this version was used to prepare Ergon Energy's 2018-19 RIN responses that was used as the source for its base year opex
- Section 9 of Ergon Energy's *new* CAM – which will apply from 1 July 2020 – instead designates fleet costs as non-network overheads (an indirect cost) that are allocated to the networks based on labour shares, *without* any depreciation costs being included.[42]

To give effect to this when forecasting opex for the 2020-25 period, Ergon Energy's base year opex was reduced by the amount of fleet depreciation reflected in it – being the $8.36 million. Although there is a change in treatment of fleet costs (from direct to indirect), there is no offset to the depreciation adjustment as the *only* change to net opex is to remove that amount.

Moreover, given that Energex's current CAM already excludes fleet depreciation costs from its share of fleet costs, there is no need to apply a similar adjustment to its base year opex.

Calculation

At the time of preparing the January 2019 Proposal for Ergon Energy, estimates of the fleet depreciation charge for 2018-19 were used as actual data was not available. For the Revised Regulatory Proposal we have used actual data, which means that we are not relying on 2018-19 budgeted information.

The data and calculations used to identify the actual fleet depreciation charge directly attributed to Ergon Energy in the 2018-19 financial years are available in the spreadsheet labelled *CAM Reconciliation - Working V4* available at Attachment *EGX ERG 7.007* (see cell E22 of the '7. Results' sheet).

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40 The $nominal value of the depreciation charge was $8.16 million.

41 See: Ergon Energy, 1 December 2018, *Cost allocation method, Version 5.0*, p. 15. The CAM is available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Cost%20allocation%20method%20-18%20October%202018.pdf.

42 See: Ergon Energy and Energex, 18 October 2018, *Cost allocation method, Version 1.a*, p. 15. Although the document does not explicitly say that fleet depreciation charges should not be included in the allocated fleet costs, the description of non-network overheads on page 12 only includes expenditure incurred to operate and maintain vehicles owned or leased (e.g. fuel, registration, vehicle maintenance). In practice, this will not include depreciation. The CAM is available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20and%20Energex%20-%20Cost%20allocation%20method%20%28effective%201%20July%202020%29%20-18%20October%202018.pdf.

Validation

Although the specific fleet depreciation value was not audited, the financial data included in our RIN responses that included it *was* audited. We also engaged PwC to review the accuracy of the modelling used to identify the depreciation attributed to Ergon Energy. PwC's report is available at Attachment *EGX ERG 7.008*.

5. Ergon Energy support cost capitalisation

Explanation

Like the fleet depreciation adjustment above, a future change to align accounting approaches across both network businesses means that for Ergon Energy a larger portion of its corporate support costs will be expensed rather than capitalised from 1 July 2020 onwards.[43] The adjustment – of positive $44.06 million[44] – increases expensed support costs allocated to Ergon Energy's 2018-19 SCS opex. An equal and opposite offsetting adjustment removes that amount from capitalised overheads.

Specifically,

- Section 9.4 of Ergon Energy's *current* CAM treats most shared corporate support costs as indirect costs and allocates them between regulated capex and opex based on direct expenditure[45]– as noted above, this version was used to prepare Ergon Energy's 2018-19 RIN responses that was used as the source for its base year opex
- Section 9 of Ergon Energy's *new* CAM – which will apply from 1 July 2020 – treats a much larger share of these corporate support costs as direct costs using time-writing data and more disaggregated account codes, which are then directly attributed to operating or capital projects.[46]

To give effect to this for its Revised Regulatory Proposal, Ergon Energy's base year opex was increased by the value of capitalised shared support costs in 2018-19 that *would have been* expensed if the new CAM had of applied – namely, the $44.06 million. To ensure consistency, Ergon Energy's base year capitalised overheads was also reduced by $44.06 million.

A similar adjustment is not required for Energex's base year because the changes reflected in the new CAM are consistent with the current Energex CAM.

Calculation

At the time of preparing the January 2019 Proposal for Ergon Energy, we used estimates of the capitalisation change for 2018-19 as actual data was not available. For the Revised Regulatory Proposal we have used actual data, which means that we are not relying on 2018-19 budgeted information.

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43 Corporate support costs include finance, human resource, ICT, legal, administrative and management services.

44 The $nominal value of the capitalisation change was $42.98 million.

45 See: Ergon Energy, 1 December 2018, *Cost allocation method, Version 5.0*, p. 18. The CAM is available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Cost%20allocation%20method%20-18%20October%202018.pdf.

46 See: Ergon Energy and Energex, 18 October 2018, *Cost allocation method, Version 1.a*, pp. 14-15. Although the document does not explicitly say that a larger share of Ergon Energy's support costs will be expensed, the effect of applying the new CAM is to increase the share that is. The CAM is available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20and%20Energex%20-%20Cost%20allocation%20method%20%28effective%201%20July%202020%29%20-18%20October%202018.pdf.

The capitalisation change was determined by comparing the actual expensed corporate overheads reported in Ergon Energy's 2018-19 RIN response to the value calculated by applying the new CAM. The data and calculations used are available at Attachment *EGX ERG 7.007* (see cell E23 of the '7. Results' sheet).

Validation

Although the specific capitalisation change value was not audited, the financial data included in our RIN responses that that was used to calculate it *was* audited. We also engaged PwC to review the accuracy of the modelling used to calculate the value. PwC's report is available at Attachment *EGX ERG 7.008*.

6. Distribution three-factor method

Explanation

The change to the CAMs also leads to a reallocation of expenditure – of $5.72 million[47] – from Ergon Energy to Energex caused from applying an improved shared support cost allocation approach referred to as the 'distribution three-factor method'.

Specifically,

- Section 9.5 of Energex's current CAM and section 9.4 of Ergon Energy's current CAM each apply slightly different approaches to allocate shared support costs to distribution and other services[48] – these versions were used to prepare the Energex and Ergon Energy 2018-19 RIN responses used to source base year opex
- Section 9.4 of Energex and Ergon Energy's *new* CAM – which will apply from 1 July 2020 – replaces the separate shared support cost allocation approaches with the distribution three-factor method.[49]

In short, the method uses three causal allocators – direct spend, customer numbers and asset value – to allocate shared support costs across Energex and Ergon Energy.[50] As described in the new CAM: [51]

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47 The $nominal value of the depreciation charge was $5.58 million.

48 See: Energex, 1 December 2018, *Cost Allocation Method*, *Version 3.a*, p. 17. Available here: https://www.aer.gov.au/system/files/Energex%20-%20Cost%20allocation%20method%20-%2018%20October%202018.pdf. And: Ergon Energy, 1 December 2018, *Cost allocation method, Version 5.0*, p. 18. Available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Cost%20allocation%20method%20-18%20October%202018.pdf.

49 See: Ergon Energy and Energex, 18 October 2018, *Cost allocation method, Version 1.a*, s. 9.4. The CAM is available here: https://www.aer.gov.au/system/files/Ergon%20Energy%20and%20Energex%20-%20Cost%20allocation%20method%20%28effective%201%20July%202020%29%20-18%20October%202018.pdf.

50 Note that the *distribution* three factor method is distinct from the *corporate* three factor method. The former allocates costs across the distribution networks, Energex and Ergon Energy; the latter instead allocates costs across legal entities within the EQL group by placing equal weight on asset value, revenue and labour.

51 See: Ergon Energy and Energex, 18 October 2018, *Cost allocation method, Version 1.a*, p. 16.

Utilising the three factor method allows consideration to be taken of the extent that expenditure is dependent on the overall size of the distribution network and effort is driven by all activities undertaken to maintain, review and manage the network business.

Because the cost allocation approaches differ between the current and new CAMs, there is a change to allocated shared support costs. For the 2018-19 financial year, applying the new CAM would re-allocate $5.72 million in shared support costs from Ergon Energy's SCS opex to Energex's. This is primarily due to Energex having relatively more customers than Ergon Energy.

Calculation

Similar to the adjustments above, at the time of preparing the January 2019 Proposals for Energex and Ergon Energy, we used estimates of the re-allocation change for 2018-19 as actual data was not available. For the Revised Regulatory Proposals we have used actual data, which means that we are not relying on 2018-19 budgeted information.

The re-allocation was determined by comparing the actual expensed corporate and network overheads reported in Ergon Energy's 2018-19 RIN response to the value calculated by applying the new CAM (adjusted to remove the capitalisation adjustment of $31.18 million noted above) – giving the $5.72 million reduction.[52] Because allocation between Ergon Energy and Energex is zero-sum, the Energex adjustment is assumed to be a $5.72 million increase.

The data and calculations used to calculate the re-allocation are available at Attachment *EGX ERG 7.007* (see cells E26 and E42 of the '7. Results' sheet).

Validation

Although the specific re-allocation value was not audited, the financial data included in our RIN responses that that was used to calculate it *was* audited. As with the other adjustments described above, we also engaged PwC to review the accuracy of the modelling used to calculate the value. PwC's report is available at Attachment *EGX ERG 7.008*.

7. Other CAM changes

Explanation

The new CAM – to be applied from 1 July 2020 – revises many of the drivers used to allocate costs between legal entities, the services provided by each entity, and capex and opex, including to SCS opex for both Energex and Ergon Energy. The revisions were introduced to provide cost reflective recovery, and consistency throughout the EQL subsidiaries.

[52] In summary, total corporate and network overheads in Ergon Energy's SCS opex for 2018-19 (based on the current CAM) was $186.94 million ($nominal). This compares to the $162.10 million ($nominal) if the new CAM is applied, giving a $24.84 million ($nominal) reduction. However, if we remove the capitalisation adjustment noted above – of a $30.42 million ($nominal) increase – then there is actually a $5.58 million ($nominal) reduction, or $5.72 million (in Real $2020).

Specific adjustments were identified in the sections above, accounting for $3.72 million for Energex and negative $4.17 million for Ergon Energy. The new CAM if applied would provide for an additional differences of $6.71 million and negative $1.22 million respectively.

Calculation

At the time of preparing the January 2019 Proposals for Energex and Ergon Energy, we used estimates of the residual impact of the CAM change for 2018-19 as actual data was not available. For the Revised Regulatory Proposals we have used actual data, which means that we are not relying on 2018-19 budgeted information.

The residual CAM impacts for each network were calculated by:

- **First**, calculating the difference between the actual SCS opex reported in the 2018-19 RIN responses – of $359.02 million for Energex and $402.37 million for Ergon Energy – to what the SCS opex would have been if the new CAM were applied – of $362.01 million and $407.76 million respectively.[53] This gives differences of $2.99 million and $5.39 million.
- **Second**, from these differences remove the other adjustments already accounted for above, which sum to positive $3.72 million for Energex and negative $4.17 million for Ergon Energy. This leaves residual adjustments of $6.71 million and negative $1.22 million respectively.[54]

The data and calculations used to calculate the residual CAM impacts are available at Attachment *EGX ERG 7.007* (see cells E27 and E43 of the '7. Results' sheet).

Validation

Although the specific SCS opex calculated based on the new CAM was not audited, the financial data included in our RIN responses that that was used to calculate it *was* audited. As with the other adjustments described above, we also engaged PwC to review the accuracy of the modelling used to calculate the value. PwC's report is available at Attachment *EGX ERG 7.008*.

53 These correspond to $nominal values of $353.16 million and $397.79 million.
54 These correspond to $nominal values of $6.54 million and negative $1.19 million.

Appendix 2. Economic Benchmarking

We engaged Frontier Economics to provide expert opinions on:

- The robustness and reliability of the benchmarking analysis relied on by the AER in the Draft Decisions, and
- Whether there is evidence to suggest that the 2018-19 base year opex used by Energex and Ergon Energy, respectively, in their internal forecasts is materially inefficient.

After undertaking that analysis, Frontier Economics concluded that there is "no evidence that either Energex's or Ergon Energy's proposed base year opex is materially inefficient".[55] This appendix summarises that analysis.

Review of AER's benchmarking approach

Frontier found material issues with the AER's benchmarking analysis, concluding that: [56]

> *The AER's benchmarking analysis suffers from major methodological shortcomings that mean the AER should interpret its benchmarking results very cautiously*

Elaborating further, Frontier recommended seven key changes to the AER's approach:

- The AER should give most weight to results from the short benchmarking period – if the AER gives any weight to the long benchmarking period, it should include the results of the SFA translog model
- If the AER continues to use data on overseas distribution network service providers (DNSPs), it should modify its models to allow Ontarian DNSPs to have a different relationship between opex and opex drivers than the Australian and New Zealand DNSPs
- The AER should modify its models to allow rural DNSPs to have a different relationship between opex and opex drivers than urban DNSPs
- The AER should exclude any OEF adjustments for bushfire obligations as it has no reliable information with which to quantify any such adjustment
- The AER should apply an OEF adjustment of +1.1% for network accessibility to Ergon Energy as it did in its 2015 Final Decision
- The AER should apply an OEF adjustment of +1.2% for OH&S regulations to Ergon Energy as it did in its 2015 Final Decision. This adjustment should also be applied to Energex
- The AER should apply the immaterial OEFs it applied to Ergon Energy and Energex in the 2015 Final Decisions.

These recommendations and the AER's findings are explained, in detail, within Frontier's report.

55 Frontier Economics, December 2019, *Assessment of the AER's benchmarking analysis*, p. 2.
56 Frontier Economics, December 2019, *Assessment of the AER's benchmarking analysis*, p. 5.

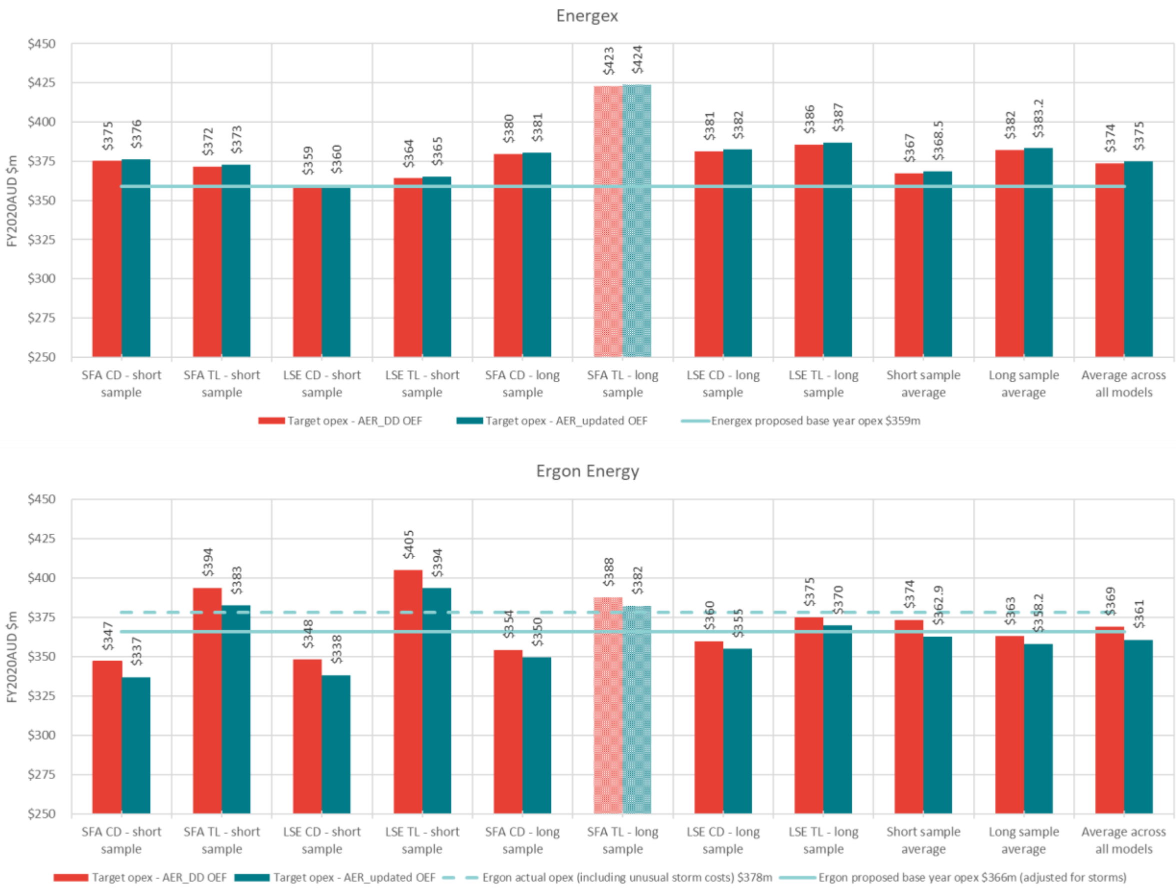
Base year efficiency

Cognisant of the findings above, Frontier compared the 2018-19 base year opex for Energex and Ergon Energy against two sets of efficiency benchmarks:

- The *first* being those estimated using the AER's approach
- The *second* being those estimated by updating the AER's approach to address the recommendations above.

In both cases, Frontier found that base 2018-19 opex for both networks was not material inefficient. Figure 10 compares that opex to benchmarks calculated using the AER's methodology. Energex's opex is well below its benchmarks, while Ergon Energy's is aligned to its, especially once the normalisation adjustment is factored. There is no basis for concluding that base year opex is inefficient.

Figure 10 Benchmarking comparison using the AER's methodology ($M, Real $2020)



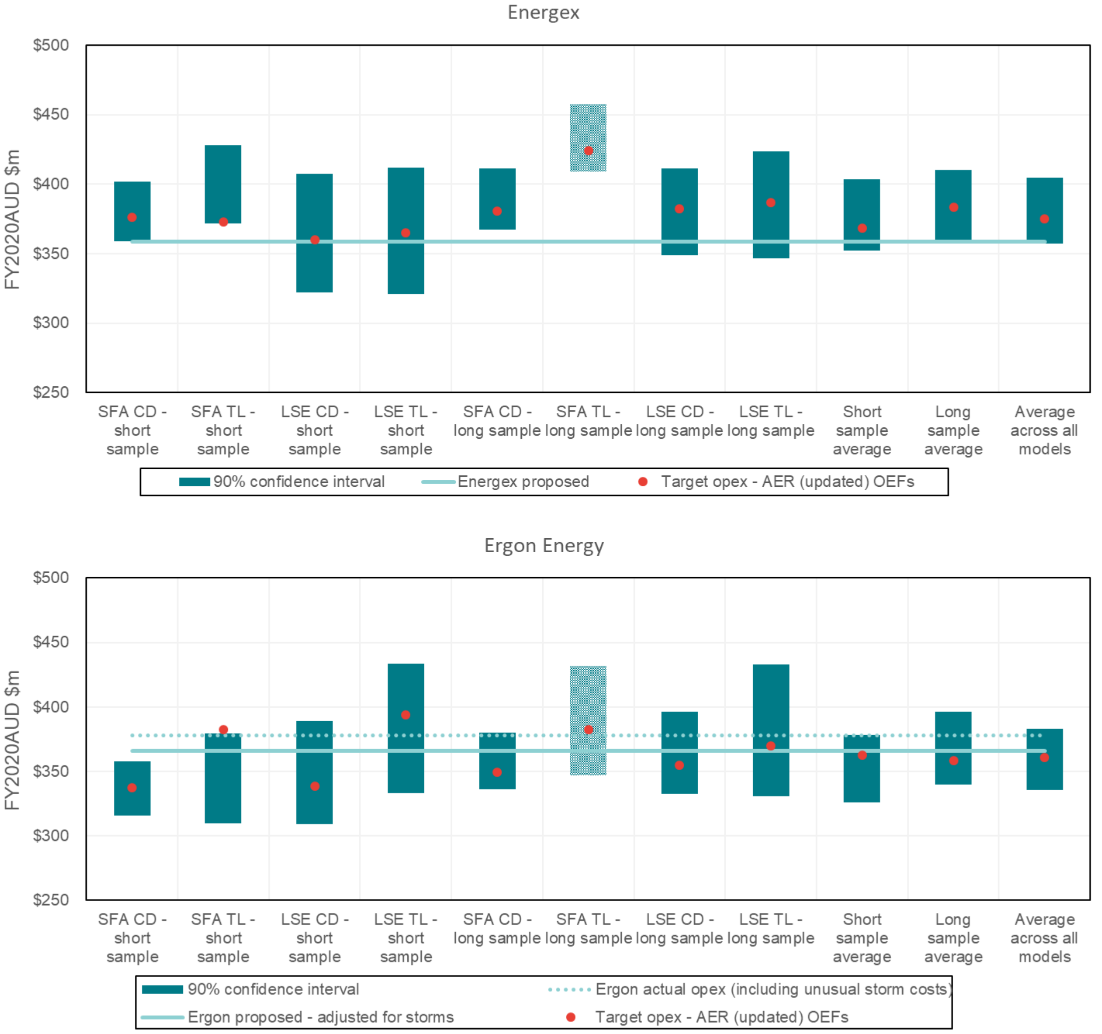
Source: Frontier Economics.

Frontier also estimated statistical confidence intervals around the efficient opex benchmarks estimated from each of the models, for the two time periods, and averages of them.[57] As shown

[57] These confidence intervals were estimated using a 90% statistical significant, which is a somewhat conservative measure as it means that the intervals are tighter. Frontier used a well-accepted bootstrapping method to determine the confidence intervals.

Figure 11, base opex for both networks either falls within or below the confidence intervals[58] – reinforcing Frontier's finding that there is no basis to conclude that base opex is materially in efficient.

Figure 11 Confidence intervals around benchmarks estimated using the AER's methodology ($M, Real $2020)



Source: Frontier Economics.

Taking this further, *if* all of Frontier's recommended OEF adjustments are made and the SFA translog model is included for the 'long' sample, then the estimated opex benchmarks and the confidence intervals around them all shift up. As shown in Figure 12, this means that base opex for both networks is at the lower end or below the confidence intervals in all cases – further reinforcing Frontier's conclusion that there is no evidence that the base year values for Energex and Ergon Energy are materially inefficient.

58 There is one exception; namely, that Ergon Energy's base opex exceeds the confidence interval for the SFA Cobb-Douglas model in the short sample. That opex is within the confidence interval for all other models and time periods and – importantly – the averages.

Figure 12 Benchmarking comparison using the AER's methodology updated for recommendations ($M, Real $2020)

Source: Frontier Economics.

Appendix 3. Ergon Energy Emergency Response Normalisation

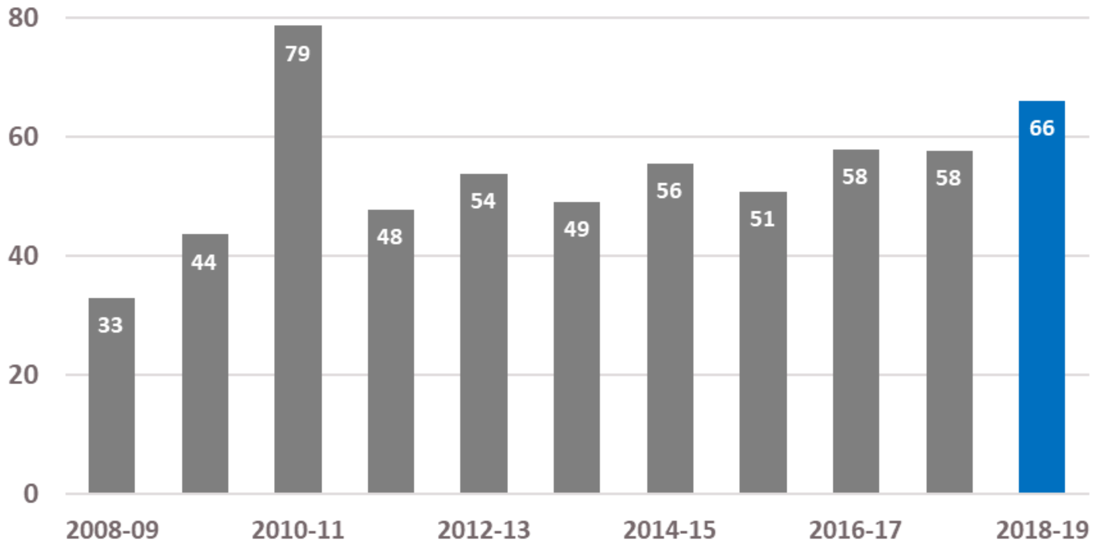
This appendix explains how the emergency response normalisation was calculated for Ergon Energy's base year.

Explanation

Ergon Energy's emergency response expenditure jumps around over time, largely because it covers of the costs of preparing for and responding to weather events that our outside of its control. As shown in Figure 13, there was a spike in costs in 2010-11 and – relevant for present purposes – another spike in 2018-19.

Given that base opex is being used to project opex over the 2020-25 period, Ergon Energy is proposing to normalise for the spike in 2018-19 by reducing it down to average emergency response expenditure over the 2008-19 period. This is explained further in the next section.

Figure 13 Ergon Energy emergency response expenditure ($M, Real $2020)



Calculation

The calculation involved four steps:

- **Firs**t, extract the historical emergency response expenditure, in nominal dollars, reported by Ergon Energy in its Category Analysis RIN responses over the 2008-2019 period[59]
- **Second**, convert that data to dollars as at 30 June 2020[60]
- **Third**, calculate the average over the period, which is $54.05 million

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[59] Nominal emergency response data was taken from Ergon Energy's category analysis RIN responses.

[60] December year on year inflation was used to first convert the nominal dollar emergency response expenditure to nominal 2018/19 dollars, which is assumed to reflect dollars as at December 2018 and is the timing assumption applying to revealed base opex. These values were then converted from December 2018 dollars to June 2020 dollars using the inflation indexes used in the 'Input|Rate of change' sheet of the opex model.

- **Fourth**, subtract the 2018-19 value (of $66.21 million) from the average to determine the normalisation adjustment of $12.16 million.

These calculations are set out in Table 18.

Table 18: Ergon Energy emergency response normalisation calculation

Year	Inflation (Dec on Dec)	Cumulative inflation adjustment to Real $2020	Emergency response expenditure ($M)	
			Nominal (**STEP 1**)	Real $2020 (**STEP 2**)
2008-09		1.265	26.10	33.03
2009-10	2.11%	1.239	35.25	43.68
2010-11	2.65%	1.207	65.26	78.77
2011-12	2.99%	1.172	40.79	47.80
2012-13	2.20%	1.147	46.95	53.84
2013-14	2.75%	1.116	43.99	49.10
2014-15	1.72%	1.097	50.70	55.63
2015-16	1.69%	1.079	47.12	50.84
2016-17	1.48%	1.063	54.49	57.94
2017-18	1.91%	1.043	55.33	57.73
2018-19	1.78%	1.265	64.59	66.21
Adjustment from December 2018 to June 2020		1.025		
Average (**STEP 3**)				**54.05**
Difference between 2018/19 and average (**STEP 4**)				**12.16**

Note: although rounded figures are shown here, unrounded figures were used and so values may not add or compute directly in the table due to rounding.

Appendix 4. Ergon Energy Overhead Recoveries True-up

This appendix explains how Ergon Energy has adjusted its reported opex to true-up between:

- Real-time overhead recoveries that were charged out during a given year using budgeted rates and point in time allocation percentages, and
- Actual year-end outcomes for these costs.

Background

In 2014, Ergon Energy amended its CAM.[61] The amended CAM came into effect at the start of the current 2015–20 regulatory control period. One of the changes in the 2015–20 CAM related to the treatment of under and over recovery of overheads (shared cost pools). Under (or over) recovery of overheads occurs when the overheads allocated to services fall short of (or exceed) actual incurred costs.[62]

Ergon Energy's 2010–15 CAM specified that where balance of under or over recovered overheads was not materially[63] significant, the balance would "reside in the regulated opex line of business*"* (i.e. be expensed), otherwise it was reallocated to capex and opex projects. We note that, in contrast, Energex always allocates the under or over recovered balance at the end of each year whether it is material or not.

Ergon Energy's 2015–20 CAM changed the wording in the CAM relating the treatment of the under or over recovery of overhead and simply stated that under or over recovery balances would "remain unallocated" (if immaterial).

The following excerpt from section 9.5 Application and Review of Shared Cost Percentage Rates in Ergon Energy's 2015–20 CAM explains this:[64]

At year end it is inevitable that the percentage rates struck throughout the year will not result in a 100% allocation of the shared (support) cost pool. Ergon Energy's experience has been that the "balance" remaining in the shared (support) cost pool is not materially significant. Ergon Energy adopts the materiality definition used in the Australian Accounting Standards.

When the unallocated balance is less than 10% of the Ergon Energy overhead pool, it shall remain unallocated. In the unlikely event that a materially significant variance arises (i.e.: greater than

61 Ergon Energy, Cost Allocation Method Version 5 .0, July 2014.

62 Under or over recovery can occur because, for accounting purposes, labour charge out rates for overhead costs are fixed *prior* to actual costs being incurred – which is needed so that costs can be allocated to cost centres in real time (e.g. when employees time-write). Although these rates are informed by past actual and expected future costs, it is not possible to know in advance what the future actual costs will be. A true-up or adjustment is often performed at the end of a financial reporting period to account for the difference between the amounts charged out (via the rates) and actual costs incurred.

63 Materiality was assessed in accordance with accounting standards at approximately $20 million.

64 See: https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Cost%20allocation%20method%20-18%20October%202018.pdf

10%), the balance will be allocated across the relevant services on the basis of proportional direct costs percentages.

Ergon Energy has applied this 2015–20 CAM in accordance with this wording over the period and had audit assurance verifying this for annual RIN reporting purposes. During this period, immaterial year end variances were not adjusted for.

Impact and outcome of adjustment

While it is a proper application of the approved CAM, excluding any under or over recovery balance deemed immaterial from its reported opex means that Ergon Energy has been either slightly understating or slightly overstating reported actual costs (within this materiality limit).

Ergon Energy has calculated the underlying actual costs where this immateriality limit is ignored, and actual costs settle to opex (i.e. in accordance with the equivalent wording of the prior CAM). This gives a better view of the actual underlying cost of its base year for opex forecasting, and is then applied consistently to prior years to maintain integrity between the base-step and trend forecasting approach and the EBSS scheme.

Table 17 sets out the impact of the change. In the first two years of the current regulatory period, reported opex is understated and the last two years opex it is overstated.

Table 19: Ergon Energy Opex and true-up impact ($M nominal)

	2015-16	2016-17	2017-18	2018-19
Reported opex	394.18	355.44	384.94	391.69
Under/(over) recovery	14.20	3.63	(13.57)	(12.56)
Adjusted/corrected opex	408.38	359.07	371.37	379.12

Appendix 5. Supporting documentation

The following documents supporting this attachment accompany our Revised Regulatory Proposal:

Table 20: Supporting documentation

Name	Ref	File name
Opex negative step changes	*EGX ERG 7.002*	EGX ERG 7.002 Opex Negative Step Changes DEC19 PUBLIC
BIS Oxford report: *Review of AER Forecast Comparison*	*EGX ERG 7.003*	EGX ERG BIS Oxford Economics 7.003 Critique of AER Approach DEC19 PUBLIC
BIS Oxford report: *Cost Escalation Forecasts to 2024/25*	*EGX ERG 7.004*	EGX ERG BIS Oxford Economics 7.004 Escalations independent expert report DEC19 PUBLIC
Frontier Economics report: *Assessment of the AER's Benchmarking Analysis*	*EGX ERG 7.005*	EGX ERG Frontier 7.005 Frontier Report DEC19 PUBLIC
Energex opex forecast model	*EGX 7.006*	EGX 7.006 Opex forecast – SCS DEC19 PUBLIC
Ergon Energy opex forecast model	*ERG 7.006*	ERG 7.006 Opex forecast – SCS DEC19 PUBLIC
Accounting adjustments spreadsheet: *CAM Reconcilliation – Working V4*	*EGX ERG 7.007*	EGX ERG 7.007 CAM Reconciliation DEC19 PUBLIC
PwC: *Report on your Cost Allocation (CAM) Model*	*EGX ERG 7.008*	EGX ERG 7.008 PWC Report - CAM Reconciliation PWC DEC19 PUBLIC